UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2001

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to .

Commission File Number 1-14365

El Paso Corporation

(formerly El Paso Energy Corporation)

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0568816**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas**	**77002**
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: (713) 420-2600
Internet Website: www.elpaso.com

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, par value $3 per share, including Preferred Stock Purchase Rights	New York Stock Exchange Pacific Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

State the aggregate market value of the voting stock held by non-affiliates of the registrant.

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of March 12, 2002, computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $23,959,866,645

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value $3 per share. Shares outstanding on March 12, 2002: 532,441,481

Documents Incorporated by Reference

List hereunder the following documents if incorporated by reference and the part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: Portions of our definitive Proxy Statement for the 2002 Annual Meeting of Stockholders, to be filed not later than 120 days after the end of the fiscal year covered by this report, are incorporated by reference into Part III.

EL PASO CORPORATION

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Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day
Bbl	= barrels
BBtu	= billion British thermal units
BBtue	= billion British thermal unit equivalents
Bcf	= billion cubic feet
Bcfe	= billion cubic feet of gas equivalents
MBbls	= thousand barrels
MMBbls	= million barrels
MMBtu	= million British thermal units
Mcf	= thousand cubic feet
Mcfe	= thousand cubic feet of gas equivalents
MMcf	= million cubic feet
MMcfe	= million cubic feet of gas equivalents
Mgal	= thousand gallons
MTons	= thousand tons
MWh	= megawatt hours
MMWh	= thousand megawatt hours
TBtu	= trillion British thermal units
Tcfe	= trillion cubic feet of gas equivalents

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

When we refer to "us", "we", "our", "ours", or "El Paso", we are describing El Paso Corporation and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

General

We are an energy company originally founded in 1928 in El Paso, Texas. For many years, we served as a regional pipeline company conducting business mainly in the western United States. Since 1995, we have grown into a global energy company whose operations extend from natural gas production and extraction to power generation. Our significant growth during this period has been accomplished through a series of strategic acquisitions, transactions and internal growth initiatives, each of which has expanded our competitive abilities in the U.S. and global energy markets. These milestones include:

Year	Transaction	Impact
1995	Acquisition of Eastex Energy Inc.	Signaled our entry into the wholesale energy marketing business.
1996	$4 billion acquisition of the energy businesses of Tenneco Inc.	Expanded our U.S. interstate pipeline system from coast to coast and signaled our entry into the international energy market.
1998	Acquisition of DeepTech International, Inc.	Expanded our U.S. onshore and offshore gathering capabilities. Established us as the general partner for El Paso Energy Partners, L.P.
1999	$7 billion merger with Sonat Inc.	Expanded our pipeline operations into the southeast portion of the U.S. and signaled our entrance into the exploration and production business.
2000	Acquisition of Pacific Gas & Electric's Texas Midstream operations	Expanded our midstream operations to cover a majority of the metropolitan markets and industrial hubs in the state of Texas.
2001	$24 billion merger with The Coastal Corporation	Placed us as a top tier participant in every aspect of the wholesale energy marketplace.

Our principal operations include:

- natural gas transportation, gathering, processing and storage;
- natural gas and oil exploration, development and production;
- energy and energy-related commodities and product marketing;
- power generation;
- energy infrastructure facility development and operation;
- petroleum refining;
- chemicals production; and
- coal mining.

Segments

Our operations are segregated into four primary business segments: Pipelines, Merchant Energy, Production and Field Services. These segments are strategic business units that provide a variety of energy products and services. We manage each segment separately, and each segment requires different technology and marketing strategies. For information relating to operating revenues, operating income, earnings before interest expense and income taxes (EBIT) and identifiable assets by segment, you should see Part II, Item 8, Financial Statements and Supplementary Data, Note 18, which is incorporated herein by reference.

Our Pipelines segment owns or has interests in approximately 60,000 miles of interstate natural gas pipelines in the U.S. and internationally. In the U.S., our systems connect the nation's principal natural gas supply regions to the five largest consuming regions in the U.S.: the Gulf Coast, California, the Northeast, the Midwest, and the Southeast. These pipelines represent one of the largest integrated coast-to-coast mainline natural gas transmission systems in the U.S. Our U.S. pipeline systems also own or have interests in over 430 Bcf of storage capacity used to provide a variety of services to our customers and own and operate a liquefied natural gas (LNG) terminal at Elba Island, Georgia that was reactivated in 2001. Our international pipeline operations include access between our U.S. based systems and Canada and Mexico as well as interests in three major operating natural gas transmission systems in Australia.

Our Merchant Energy segment is involved in a broad range of energy-related activities including asset ownership, customer origination, marketing and trading and financial services. We are one of North America's premier wholesale energy commodity marketers and traders, and we buy, sell and trade natural gas, power, crude oil, refined products, coal and other energy commodities in the U.S. and internationally. We are also a significant owner of electric generating capacity and own or have interests in 95 facilities in 20 countries. The three refineries we operate have the capacity to process approximately 438 MBbls of crude oil per day and produce a variety of petroleum products. We also produce agricultural and industrial chemicals at five facilities in the U.S. Our coal mining operations produce high-quality, bituminous coal with reserves in Kentucky, Virginia and West Virginia. Our financial services businesses manage investments in the North American energy industry. Most recently, Merchant Energy has announced its expansion into the LNG business.

Our Production segment leases approximately 5 million net acres in 19 states, including Colorado, Louisiana, Oklahoma, Texas, Utah, West Virginia and Wyoming, and in the Gulf of Mexico. We also have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey. During 2001, daily equivalent natural gas production exceeded 1.7 Bcfe/d, and our reserves at December 31, 2001, were approximately 6.7 Tcfe.

Our Field Services segment provides natural gas gathering, products extraction, fractionation, dehydration, purification, compression and intrastate transmission services. These services include gathering natural gas from more than 15,000 natural gas wells with approximately 21,000 miles of natural gas gathering and natural gas liquids pipelines, and approximately 30 natural gas processing, treating and fractionation facilities located in some of the most active production areas in the U.S., including the San Juan Basin, east and south Texas, Louisiana, the Gulf of Mexico and the Rocky Mountains. We conduct our intrastate transmission operations through interests in six intrastate systems, which serve a majority of the metropolitan areas and industrial load centers in Texas as well as markets in Louisiana. Our primary vehicle for growth and development of midstream energy assets is El Paso Energy Partners, L.P., a publicly traded master limited partnership in which we serve as the general partner. El Paso Energy Partners provides natural gas, natural gas liquids and oil gathering and transportation, storage and other related services.

Pipelines Segment

Our Pipelines segment provides natural gas transmission services in the U.S. and internationally. We conduct our activities through seven wholly owned and eight partially owned interstate transmission systems along with six underground natural gas storage facilities and a LNG terminalling facility. The tables below detail our wholly owned and partially owned interstate transmission systems:

Wholly Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	Miles of Pipeline	Design Capacity	Average Throughput[1] 2001	2000	1999	Storage Capacity
			(MMcf/d)		(BBtu/d)		(Bcf)
Tennessee Gas Pipeline (TGP)	Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including New York City and Boston.	14,200	6,194	4,405	4,354	4,253	95
ANR Pipeline (ANR)	Extends from Texas, Oklahoma, Louisiana and the Gulf of Mexico to the Midwest and northeast regions of the U.S., including Detroit, Chicago and Milwaukee.	10,600	6,394	3,776	3,807	3,515	202
El Paso Natural Gas (EPNG)	Extends from the San Juan Basin of northern New Mexico and southern Colorado and the Permian and Anadarko Basins to California, Nevada, Arizona, New Mexico, Texas, Oklahoma and northern Mexico.	10,000	4,744	4,253	3,937	3,603	—
Southern Natural Gas (SNG)	Extends from Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including Atlanta and Birmingham.	8,200	2,829	1,877	2,132	2,077	60
Colorado Interstate Gas (CIG)	Extends from most production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and various interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest.	4,600	2,928	1,448	1,383	1,301	29
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to the CIG-Trailblazer interconnect near Cheyenne, Wyoming on the 800-mile Trailblazer system and into other interstate and intrastate pipelines.	600	1,860	1,017	832	657	—
Mojave Pipeline (MPC)	Connects with the EPNG system at Topock, Arizona and the Kern River Gas Transmission Company and Transwestern systems in California, extending to customers and a pipeline interconnect in the vicinity of Bakersfield, California.	400	400	283	407	391	—

(1) Includes throughput transported on behalf of affiliates.

Partially Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	Ownership Interest	Miles of Pipeline	Design Capacity[1]	Average Throughput[1] 2001	2000	1999
		(Percent)		(MMcf/d)	(BBtu/d)		
Florida Gas Transmission	Extends from south Texas to Florida.	50	4,700	1,700	1,616	1,524	1,497
Alliance Pipeline[2]	Extends from western Canada to Chicago.	14	2,345	1,537	1,479	105	—
Great Lakes Gas Transmission	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,100	2,895	2,224	2,477	2,602
Dampier-to-Bunbury pipeline system	Extends from Dampier to Bunbury in western Australia.	33	925	570	555	523	485
Moomba-to-Adelaide pipeline system	Extends from Moomba to Adelaide in southern Australia.	33	488	383	261	231	220
Ballera-to-Wallumbilla pipeline system	Extends from Ballera to Wallumbilla in southwestern Queensland, Australia.	33	470	115	71	71	59
Portland Natural Gas Transmission	Extends from the Canadian border near Pittsburg, New Hampshire to Dracut, Massachusetts.	30[3]	300	214	123	110	61
Overthrust Pipeline Company	Extends from the Whitney Canyon area near the Utah-Wyoming border to Rock Springs, Wyoming.	10	88	227	87	85	140

(1) Volumes represent the systems' total design capacity and average throughput and are not adjusted for our ownership interest.
(2) The Alliance pipeline project commenced operations in the fourth quarter of 2000.
(3) Our ownership interest increased from 19 percent to 30 percent effective June 2001.

In addition to the storage capacity on our transmission systems, we own or have interests in the following natural gas storage facilities:

Underground Natural Gas Storage Facilities

Storage Facility	Ownership Interest	Storage Capacity[1]	Location
	(Percent)	(Bcf)	
Bear Creek Storage	100	58	Louisiana
ANR Storage	100	56	Michigan
Blue Lake Gas Storage	75	47	Michigan
Eaton Rapids Gas Storage	50	13	Michigan
Steuben Gas Storage	50	6	New York
Young Gas Storage	48	5	Colorado

(1) Includes a total of 133 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.

In addition to our operations of natural gas pipeline systems and storage facilities, we own a LNG receiving terminal located on Elba Island, near Savannah, Georgia. The facility is capable of achieving a peak send out of 675 MMcf/d and a base load send out of 446 MMcf/d and was reactivated in December 2001.

We have a number of transmission system expansion projects that have been approved by the Federal Energy Regulatory Commission (FERC) as follows:

Transmission System	Project	Capacity (MMcf/d)	Description[(1)]	Anticipated Completion Date
TGP	FPL project	90	Installation of compression and a meter to supply Florida Power and Light's facility in Rhode Island.	September 2002
TGP	Stagecoach	100	Connect the Stagecoach Storage Field in New York to our mainline in Pennsylvania and expand our 300 Line to provide firm transportation service to interconnect with New Jersey Natural in Passaic, New Jersey.	Completed February 2002
ANR	PG&E Badger	210	A lateral pipeline to supply natural gas to a PG&E facility located in southeast Wisconsin.	May 2004
EPNG	Line 2000	230	Conversion of a pipeline from oil transmission to natural gas transmission from West Texas to the Arizona and California border.	September 2002
SNG	South System I	336	Installation of compression and pipeline looping to increase firm transportation capacity along SNG's south mainline in Alabama, Georgia and South Carolina.	June 2002 and June 2003
SNG	North System II	33	Installation of compression and additional pipeline looping to increase capacity along SNG's north mainline in Alabama.	June 2003
CIG	Front Range Expansion	283	Installation of compression and pipeline looping to increase deliverability along the Colorado Front Range market area.	December 2002

(1) Pipeline looping is the installation of a pipeline, parallel to an existing pipeline, with tie-ins at several points along the existing pipeline. Looping increases the transmission system's capacity.

Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Generally, the FERC's authority extends to:

- transportation and storage of natural gas, rates and charges;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipeline and marketing affiliates;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

Our wholly and partially owned domestic pipelines and storage facilities have tariffs established through filings with the FERC that have a variety of terms and conditions, each of which affects their operations and their ability to recover fees for the services they provide. Generally, changes to these fees or terms of service can only be implemented upon approval by the FERC.

In Canada, our pipeline operating activities are regulated by the National Energy Board. Similar to the FERC, the National Energy Board governs tariffs and rates, and the construction and operation of natural gas pipelines in Canada. In Australia, various regional and national agencies regulate the tariffs, rates and operating activities of natural gas pipelines.

Our interstate pipeline systems are also subject to the Natural Gas Pipeline Safety Act of 1968, which establishes pipeline and LNG plant safety requirements, the National Environmental Policy Act and other environmental legislation. Each of our systems has a continuing program of inspection designed to keep all of our facilities in compliance with pollution control and pipeline safety requirements. We believe that our systems are in compliance with the applicable requirements.

We are also subject to regulation with respect to safety requirements in the design, construction, operation and maintenance of our interstate natural gas transmission and storage facilities by the U.S. Department of Transportation. Additionally, we are subject to similar safety requirements from the U.S. Department of Labor's Occupational Safety and Health Administration related to our processing plants. Operations on U.S. government land are regulated by the U.S. Department of the Interior.

For a discussion of significant rate and regulatory matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 14.

Markets and Competition

Our interstate transmission systems face varying degrees of competition from other pipelines, as well as alternative energy sources, such as electricity, hydroelectric power, coal and fuel oil. Also, the potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation may benefit the natural gas industry by creating more demand for natural gas turbine generated electric power, or it may hamper demand by allowing a more effective use of surplus electric capacity through increased wheeling as a result of open access. The following table details our markets and competition on each of our wholly owned pipeline systems:

Transmission System	Customer Information[1]	Contract Information	Competition
TGP	Approximately 430 firm and interruptible customers Major Customers: None of which individually represents more than 10 percent of revenues	Approximately 500 firm contracts Contracted capacity: 95% Remaining contract term: 1 month to 10 years Average remaining contract term: 5 years	TGP faces strong competition in the Northeast, Appalachian, Midwest and Southeast market areas. It competes with interstate pipelines for deliveries to multiple-connection customers. Natural gas delivered on the TGP system competes with alternate fuels, principally oil and coal. It also competes with pipelines and local distribution companies to connect new loads. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and at the Canadian border.
ANR	Approximately 250 firm and interruptible customers Major Customer: Wisconsin Gas Company (772 BBtu/d)	Approximately 600 firm contracts Contracted capacity: 97% Remaining contract term: 5 months to 23 years Average remaining contract term: 5 years Contract terms expire in 2002-2008.	In Wisconsin and Michigan, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast markets, ANR competes with other interstate pipelines serving electric generation and local distribution companies. Also, Wisconsin Gas is a sponsor of the proposed Guardian Pipeline, which is expected to be in service by the spring of 2002, and will directly compete for a portion of the markets served by ANR's expiring capacity.
EPNG	Approximately 390 firm and interruptible customers Major Customer: Southern California Gas Company (1,175 BBtu/d)	Approximately 200 firm contracts Contracted capacity: 100% Remaining contract term: 1 month to 29 years Average remaining contract term: 6 years Contract term expires in 2006	EPNG faces competition from other pipeline companies that transport natural gas to the California market as well as hydroelectric power producers who provide a significant amount of power to that state.

(1) Includes natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies.

System	Customer Information[(1)]	Contract Information	Competition
SNG	Approximately 260 firm and interruptible customers Major Customers: Atlanta Gas Light Company (786 BBtu/d) Alabama Gas Corporation (392 BBtu/d) South Carolina Pipeline Corporation (192 BBtu/d)	Approximately 170 firm contracts Contracted capacity: 100% Remaining contract term: 1 month to 27 years Average remaining contract term: 11 years Contract terms expire in 2005-2007. Contract terms expire in 2005-2008. Contract terms expire in 2005-2006.	Competition is strong in a number of SNG's key markets. SNG's three largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, SNG competes with several pipelines for the transportation business of many of its other customers.
CIG	Approximately 165 firm and interruptible customers Major Customer: Public Service Company of Colorado (1,231 BBtu/d)	Approximately 160 firm contracts Contracted capacity: 100% Remaining contract term: 2 months to 23 years Average remaining contract term: 7 years Contract term expires in 2007.	In CIG's "on-system" market, competition comes from local supply in the Denver-Julesburg basin, from an intrastate pipeline directly serving Denver and from off-system shippers who can deliver their gas in that market, supplanting CIG transportation for on-system customers. In its "off-system" market, CIG faces competition in its supply areas from competitors who can ship natural gas to the Midwest, California, the Southwest and the Pacific Northwest.
WIC	Approximately 45 firm and interruptible customers Major Customers: Colorado Interstate Gas Company (247 BBtu/d) Western Gas Resources (206 BBtu/d) Williams Energy Marketing and Trading (177 BBtu/d)	Approximately 50 firm contracts Contracted capacity: 100% Remaining contract term: 9 months to 18 years Average remaining contract term: 6 years Contract terms expire in 2003-2007. Contract terms expire in 2003-2013. Contract terms expire in 2003-2013.	WIC competes with eight interstate pipelines and one intrastate pipeline for supply access. Additionally, WIC's two lines feed into the Trailblazer system going east, the CIG system going south and other interstate and intrastate pipelines connected at the CIG-Trailblazer interconnect.
MPC	Approximately 15 firm and interruptible customers Major Customers: Texaco Natural Gas Inc. (185 BBtu/d) Burlington Resources Trading Inc. (76 BBtu/d) Los Angeles Department of Water and Power (50 BBtu/d)	Approximately 10 firm contracts Contracted capacity: 98% Remaining contract term: 5 years Average remaining contract term: 5 years Contract term expires in 2007. Contract term expires in 2007. Contract term expires in 2007.	MPC faces competitive pressures from supplies in the Rocky Mountains, new supplies within California, interstate pipeline expansions, changes in local distribution companies and California intrastate pipeline operating procedures, as well as deregulation of electric generation facilities.

(1) Includes natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies.

The ability of our pipeline systems to extend their existing contracts or re-market expiring capacity with their customers is based on a variety of factors, including competitive alternatives, the regulatory environment at the local, state and federal levels and market supply and demand factors at the relevant extension or expiration dates. While every attempt is made to re-negotiate contract terms at fully-subscribed quantities and at maximum rates allowed under their tariffs, our pipelines must at times discount their rates to remain competitive.

Merchant Energy Segment

Our Merchant Energy segment is involved in a broad range of activities in the energy marketplace, including asset ownership, customer origination, marketing and trading and financial services.

Asset Ownership

Merchant Energy's Asset Ownership activities include ownership interests in domestic and international power generation, refining and chemicals operations, coal mining and an emerging LNG business.

Power Generation. Our commercial focus in the power generation business is to either develop projects in which new long-term power purchase agreements allow for an acceptable return on capital, or to acquire projects with existing attractive power purchase agreements. Under this strategy, we have become a significant U.S.-based independent power generator and currently own or have interests in 95 power plants in 20 countries. These plants represent 22,109 gross megawatts of generating capacity, 85 percent of which is sold under power purchase or tolling agreements with terms in excess of five years. Of these facilities, 61 percent are natural gas fired, 11 percent are geothermal and 28 percent are a combination of coal, natural gas liquids and hydroelectric.

A significant portion of our domestic activity is conducted within an unconsolidated affiliate, Chaparral Investors, L.L.C. Chaparral's primary strategy is to acquire power plants with above-market power contracts and restructure these contracts by offering a lower power sales cost to the plants' customers, which are typically electric utilities. Through Chaparral (an entity that we have also referred to in our public disclosures as Electron), we have invested in 39 U.S. power generation facilities with a total generating capacity of approximately 5,900 gross megawatts. We serve as the manager of Chaparral under a management agreement that expires in 2006, and are paid an annual performance-based fee for the services we perform under this agreement. Our activities as manager of Chaparral include:

- management of the operations and commercial activities of the facilities;
- project-level contract restructurings and monetizations;
- project financings, sales and acquisitions;
- identification, evaluation, negotiation and consummation of new investments in energy assets; and
- daily administration activities of accounting, tax, legal and treasury functions.

Internationally, our focus is on building energy infrastructure in developed economies, and to a lesser degree in selected emerging markets. Our primary areas of focus include Brazil, Europe, Korea and Japan. We principally conduct our Brazilian development activities within an unconsolidated affiliate that we refer to as Gemstone. Through our ownership interest in Gemstone, we have invested in five Brazilian power generation facilities with a total generating capacity of approximately 2,156 gross megawatts. We serve as the manager of Gemstone under a management agreement that expires in 2004. Our activities as manager of Gemstone are similar to those described above for Chaparral.

Detailed below are our power generation projects, by region, that are either operational or in various stages of construction:

Region	Project Status	Number of Facilities	Gross Megawatts	Net[1] Megawatts
North America				
East Coast	Operational	22	3,325	2,397
	Under Construction	3	1,390	1,361
Central	Operational	6	1,975	1,086
	Under Construction	3	1,144	617
West Coast	Operational	26	1,694	665
South America	Operational	8	4,984	1,976
	Under Construction	1	470	282
Asia	Operational	14	3,528	1,875
	Under Construction	1	762	189
Central America	Operational	5	1,148	408
	Under Construction	1	49	10
Europe	Operational	4	940	940
Mexico	Operational	1	700	700
Total		95	22,109	12,506

(1) Net Megawatts represent our net ownership in the facilities.

Refining and Chemicals. Our Refining and Chemicals business: (i) owns or has interests in four crude oil refineries and five chemical production facilities; (ii) has petroleum terminalling and related marketing operations; and (iii) has blending and packaging operations that produce and distribute a variety of lubricants and automotive related products. The refineries we operate have a throughput capability of approximately 438 MBbls of crude oil per day to produce a variety of gasolines, diesel fuels, asphalt, industrial fuels and other products. Our chemical facilities have a production capability of 3,800 tons per day and produce various industrial and agricultural products.

In 2001, our refineries operated at 70 percent of their average combined capacity and at 93 percent in each of 2000 and 1999. The aggregate sales volumes at our wholly owned refineries were approximately 131 MMBbls in 2001, 182 MMBbls in 2000 and 171 MMBbls in 1999. Of our total refinery sales in 2001, 39 percent was gasoline, 39 percent was middle distillates, such as jet fuel, diesel fuel and home heating oil, and 22 percent was heavy industrial fuels and other products.

The following table presents average daily throughput and storage capacity at our wholly owned refineries at December 31:

Refinery	Location	Average Daily Throughput 2001	2000	1999	At December 31, 2001 Daily Capacity	Storage Capacity
		(In MBbls)				
Aruba	Aruba	178	229	195	280	15,258
Eagle Point	Westville, New Jersey	118	143	143	140	8,854
Corpus Christi[1]	Corpus Christi, Texas	38	99	100	—	—
Mobile	Mobile, Alabama	10	12	13	18	600
Total		344	483	451	438	24,712

(1) In June 2001, we leased our Corpus Christi refinery to Valero Energy Corporation. The lease is for 20 years, and Valero has an option to purchase the refinery beginning in 2003. These volumes only reflect those produced prior to our lease of the facilities.

Our chemical plants produce agricultural fertilizers, gasoline additives and other industrial products from facilities in Nevada, Oregon, Texas and Wyoming. The following table presents sales volumes from our wholly owned chemical facilities for each of the three years ended December 31:

	2001	2000	1999
		(MTons)	
Industrial	492	547	608
Agricultural	378	389	326
Gasoline additives	173	214	209
Total	1,043	1,150	1,143

Coal Mining. Our Coal mining business controls reserves totaling 524 million recoverable tons and produces high-quality bituminous coal from reserves in Kentucky, Virginia and West Virginia. The extracted coal is primarily sold under long-term contracts to power generation facilities in the eastern U.S. During the year ended December 31, 2001, coal production totaled 11.5 million tons.

LNG. Our LNG business contracts for LNG terminalling and regasification capacity, coordinates short and long term LNG supply deliveries and is developing an international LNG supply, marketing and infrastructure business. As of December 31, 2001, our LNG business had contracted for 284 Bcf per year of LNG regasification capacity at three locations along the Eastern and Gulf of Mexico coastal regions of the U.S. as follows:

Facility	Location	Contracted Capacity	Contracted In Service Date	Expiration Date
		(MMcf/d)		
Elba Island	Georgia	446	2001	2023
Cove Point	Maryland	250	2002	2022
Lake Charles	Louisiana	82	2003	2007

We have also contracted for 105 Bcf per year of long-term supplies of LNG at market sensitive prices, which will be delivered from the Caribbean beginning in 2002. In addition, we have contracted to lease four LNG tankers to transport LNG from supply areas to domestic and international market centers. These ships are currently being constructed by third parties with the first ship scheduled for delivery in 2003.

Operations. Merchant Energy has established an Operations group to manage the daily operations of Merchant Energy's worldwide assets. This group operates 22 generating facilities in the U.S. and eight facilities in six foreign countries.

Customer Origination, Marketing and Trading

Our Merchant Energy segment is one of the largest energy marketers in North America, and manages a large network of energy shipping, transmission, transportation, terminalling, refining and generation assets, both owned and under contract, which are used in the delivery of natural gas, petroleum, petroleum products and power. Merchant Energy's customer origination activities provide short and long-term supplies of energy commodities to a broad range of wholesale customers worldwide. These activities provide customers with alternatives to meet their energy supply needs and manage their associated energy risks through Merchant Energy's: (i) knowledge of the marketplace; (ii) network of delivery infrastructure; (iii) supply aggregation and transportation management capabilities; and (iv) valuation and integrated price risk management skills. Merchant Energy's marketing and trading groups trade natural gas, power, crude oil, other energy commodities and related financial instruments in North America and Europe and provide pricing and valuation analysis for the entire segment. These groups manage the inherent risk of Merchant Energy's asset and trading portfolios using value-at-risk limits approved by the Audit Committee of our Board of Directors and attempt to optimize the value of the segment's asset portfolio.

During 2001, Merchant Energy's traded volumes increased across all commodity groups. Detailed below is the marketed and traded energy commodity volumes for each of the three years ended December 31:

Volumes	2001	2000	1999
Physical			
Natural gas (BBtue/d)	9,230	7,768	6,713
Power (MMWh)	221,075	118,672	79,361
Crude oil and refined products (MBbls)	698,933	667,834	664,935
Coal (MTons)	10,343	9,834	8,980
Financial settlements (BBtue/d)	232,282	151,115	113,814

Financial Services

Our Financial Services group provides institutional and retail funds management and makes capital investments for Merchant Energy. It conducts these activities primarily through two subsidiaries, EnCap Investments L.L.C., and Enerplus Global Investment Management, Inc.

EnCap is an institutional funds management firm specializing in financing independent oil and natural gas producers. EnCap manages four separate institutional oil and natural gas investment funds in the U.S. and serves as investment advisor to Energy Capital Investment Company PLC, a publicly traded investment company in the United Kingdom. Enerplus is an institutional and retail funds management firm in Canada. EnCap and Enerplus manage funds that had a combined market value of approximately $1.4 billion at December 31, 2001.

Regulatory Environment

Merchant Energy's domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to its rates, terms and conditions of service. In addition, exports of electricity outside of the U.S. must be approved by the Department of Energy. Its cogeneration power production activities are regulated by the FERC under the Public Utility Regulatory Policies Act (PURPA) with respect to rates, procurement and provision of services and operating standards. Its power generation and refining, chemical and petroleum activities are also subject to federal and state environmental regulations, including the U.S. Environmental Protection Agency (EPA) regulations. We believe that our operations are in compliance with the applicable requirements.

Merchant Energy's foreign operations are regulated by numerous governmental agencies in the countries in which these projects are located. Many of the countries in which Merchant Energy conducts and will conduct business have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures and their interpretation and application by administrative agencies are relatively new and sometimes limited. Many detailed rules and procedures are yet to be issued, and we expect that the interpretation of existing rules in these jurisdictions will evolve over time. We believe that our operations are in compliance with all environmental laws and regulations in the applicable foreign jurisdictions.

Markets and Competition

Merchant Energy maintains a diverse supplier and customer base. During 2001, its activities served over 4,600 suppliers and 6,700 customers around the world.

Merchant Energy's trading, marketing, refining, chemicals and energy infrastructure development businesses operate in a highly competitive environment. Its primary competitors include:

- affiliates of major oil and natural gas producers;
- multi-national energy infrastructure companies;
- large domestic and foreign utility companies;

- affiliates of large local distribution companies;
- affiliates of other interstate and intrastate pipelines;
- independent energy marketers and power producers with varying scopes of operations and financial resources; and
- independent refining and chemical companies.

Merchant Energy competes on the basis of price, access to production, imbalance management, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served by Merchant Energy is influenced directly or indirectly by energy market economics.

Many of Merchant Energy's generation facilities sell power pursuant to long-term agreements with investor-owned utilities in the U.S. The terms of its power purchase agreements for its facilities are such that Merchant Energy's revenues from these facilities are not significantly impacted by competition from other sources of generation. The power generation industry is rapidly evolving and regulatory initiatives have been adopted at the federal and state level aimed at increasing competition in the power generation business. As a result, it is likely that when the power purchase agreements expire, these facilities will be required to compete in a significantly different market in which operating efficiency and other economic factors will determine success. Merchant Energy is likely to face intense competition from generation companies as well as from the wholesale power markets. The successful acquisition of new business opportunities is dependent on Merchant Energy's ability to respond to requests to provide new services, mitigate potential risks and maintain strong business development, legal, financial and operational support teams with experience in the marketplace.

Production Segment

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. In the U.S., we have onshore properties in 19 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey.

Production primarily sells its natural gas to third parties through our Merchant Energy segment at spot-market prices. It sells its natural gas liquids at market prices under monthly or long-term contracts and its oil production at posted prices, subject to adjustments for gravity and transportation. Production engages in hedging activities on its natural gas and oil production to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. During 2001, approximately 80 percent of the segment's overall production was hedged at fixed prices.

Strategically, Production emphasizes disciplined investment criteria and manages its existing production portfolio to maximize volumes and minimize costs. It employs geophysical technology and seismic data processing to identify economic hydrocarbon reserves. Production's deep drilling capabilities and hydraulic fracturing technology allow it to optimize production with high-rate completions at attractive reserve replacement costs. Production maintains an active drilling program that capitalizes on its land and seismic holdings. It also acquires production properties subject to acceptable investment return criteria.

Natural Gas and Oil Reserves

The table below details Production's proved reserves at December 31, 2001. Information in this table is based on the reserve report dated January 1, 2002, prepared internally by Production and reviewed by Huddleston & Co., Inc. This information agrees with estimates of reserves filed with other federal agencies except for differences of less than 5 percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. These reserves include 124,158 MMcfe of production delivery commitments under financing arrangements that extend through 2005. Total proved reserves on the fields with this dedicated production were 1,981,239 MMcfe. In addition, the table excludes Production's 50 percent interest in UnoPaso (Pescada in Brazil), Merchant Energy's 50 percent equity interest in Sengkang in Indonesia, Merchant Energy's 45 percent and 24.75 percent equity interests in

CAPSA and CAPEX in Argentina and Field Services' 27 percent equity interest in El Paso Energy Partners. Combined proved natural gas reserves balances for these equity interests were 361,997 MMcf, liquids reserves were 44,711 MBbls and natural gas equivalents were 630,263 MMcfe, all net of our ownership interests.

	Net Proved Reserves[1]		
	Natural Gas (MMcf)	Liquids[2] (MBbls)	Total (MMcfe)
Production			
United States			
Producing	2,387,210	69,636	2,805,026
Non-Producing	579,918	22,424	714,462
Undeveloped	2,492,703	54,103	2,817,321
Total proved	5,459,831	146,163	6,336,809
Canada			
Producing	107,843	6,580	147,323
Non-Producing	30,255	761	34,821
Undeveloped	48,213	3,541	69,459
Total proved	186,311	10,882	251,603
Other Countries[3]			
Producing	—	—	—
Non-Producing	—	—	—
Undeveloped	40,130	7,771	86,756
Total proved	40,130	7,771	86,756
Worldwide			
Producing	2,495,053	76,216	2,952,349
Non-Producing	610,173	23,185	749,283
Undeveloped	2,581,046	65,415	2,973,536
Total proved	5,686,272	164,816	6,675,168
Natural Gas Systems[4]			
Producing	182,857	97	183,439
Non-Producing	—	—	—
Undeveloped	—	—	—
Total proved	182,857	97	183,439

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.
(2) Includes oil, condensate and natural gas liquids.
(3) Includes international operations in Brazil and Indonesia.
(4) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of Production. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties owned by Production declines as reserves are depleted. Except to the extent Production conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the proved reserves of Production will decline as reserves are produced.

For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, Note 22.

Wells and Acreage

The following table details Production's gross and net interest in developed and undeveloped onshore, offshore, coal seam and international acreage at December 31, 2001. Any acreage in which Production's interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Production						
United States						
Onshore	2,222,137	1,220,912	1,990,014	1,317,950	4,212,151	2,538,862
Offshore	854,896	552,272	1,065,789	1,018,963	1,920,685	1,571,235
Coal Seam	128,781	61,149	1,027,532	637,339	1,156,313	698,488
Total	3,205,814	1,834,333	4,083,335	2,974,252	7,289,149	4,808,585
International						
Australia	—	—	1,770,364	613,600	1,770,364	613,600
Bolivia	—	—	154,840	15,484	154,840	15,484
Brazil	—	—	5,570,315	4,089,259	5,570,315	4,089,259
Canada	838,300	615,373	290,370	130,528	1,128,670	745,901
Hungary	—	—	568,100	568,100	568,100	568,100
Indonesia	—	—	1,373,691	442,606	1,373,691	442,606
Turkey	—	—	4,488,742	2,244,371	4,488,742	2,244,371
Total	838,300	615,373	14,216,422	8,103,948	15,054,722	8,719,321
Worldwide Total	4,044,114	2,449,706	18,299,757	11,078,200	22,343,871	13,527,906
Natural Gas Systems						
Domestic Onshore	262,474	259,276	—	—	262,474	259,276
Total	4,306,588	2,708,982	18,299,757	11,078,200	22,606,345	13,787,182

The U.S. domestic net developed acreage is concentrated primarily in the Gulf of Mexico (26 percent), Texas (24 percent), Utah (17 percent), Colorado (8 percent), Oklahoma (7 percent), West Virginia (6 percent), Wyoming (5 percent) and Louisiana (5 percent). Approximately 20 percent, 15 percent and 14 percent of our total U.S. net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2002, 2003 and 2004.

The following table details Production's working interests in onshore, offshore, coal seam and international natural gas and oil wells at December 31, 2001:

	Productive Natural Gas Wells		Productive Oil Wells		Total Productive Wells		Number of Wells Being Drilled	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Production								
United States								
Onshore	4,000	3,025	496	332	4,496	3,357	35	26
Offshore	371	179	123	41	494	220	4	3
Coal Seam	1,424	659	—	—	1,424	659	6	1
Total	5,795	3,863	619	373	6,414	4,236	45	30
International								
Canada	305	178	264	122	569	300	7	4
Worldwide Total	6,100	4,041	883	495	6,983	4,536	52	34
Natural Gas Systems								
Domestic Onshore	879	806	9	8	888	814	—	—
Total	6,979	4,847	892	503	7,871	5,350	52	34

The following table details Production's exploratory and development wells drilled during the years 1999 through 2001:

	Net Exploratory Wells Drilled			Net Development Wells Drilled		
	2001	2000	1999	2001	2000	1999
Production						
United States						
Productive	17	16	19	449	424	297
Dry	8	17	19	23	18	3
Total	25	33	38	472	442	300
Canada						
Productive	12	3	5	47	10	2
Dry	12	3	—	26	1	2
Total	24	6	5	73	11	4
Other Countries[1]						
Productive	—	—	—	—	—	—
Dry	9	1	—	1	—	—
Total	9	1	—	1	—	—
Worldwide						
Productive	29	19	24	496	434	299
Dry	29	21	19	50	19	5
Total	58	40	43	546	453	304
Natural Gas Systems						
Productive	—	—	—	17	1	13
Dry	—	—	—	—	—	—
Total	—	—	—	17	1	13
Total	58	40	43	563	454	317

(1) Includes international operations in Australia, Brazil, Turkey and Indonesia.

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

Net Production, Unit Prices and Production Costs

The following table details Production's net production volumes, average sales prices received and average production costs associated with the sale of natural gas and oil for each of the three years ended December 31:

Production	2001	2000	1999
United States			
Net Production:			
Natural Gas (Bcf)	552	516	416
Oil, Condensate and Liquids (MMBbls)	13	12	10
Total (Bcfe)	634	586	478
Average Sales Price(1):			
Natural Gas ($/Mcf)	$ 3.46	$ 2.62	$ 2.11
Oil, Condensate and Liquids ($/Bbl)	$21.82	$21.82	$15.03
Average Production Cost ($/Mcfe)(2)	$ 0.51	$ 0.41	$ 0.42
Canada			
Net Production:			
Natural Gas (Bcf)	13	1	—
Oil, Condensate and Liquids (MMBbls)	1	—	—
Total (Bcfe)	17	1	—
Average Sales Price(1):			
Natural Gas ($/Mcf)	$ 2.68	$ 4.09	$ —
Oil, Condensate and Liquids ($/Bbl)	$18.26	$ —	$ —
Average Production Cost ($/Mcfe)(2)	$ 0.74	$ 0.66	$ —
Worldwide			
Net Production:			
Natural Gas (Bcf)	565	517	416
Oil, Condensate and Liquids (MMBbls)	14	12	10
Total (Bcfe)	651	587	478
Average Sales Price(1):			
Natural Gas ($/Mcf)	$ 3.44	$ 2.62	$ 2.11
Oil, Condensate and Liquids ($/Bbl)	$21.68	$21.82	$15.03
Average Production Cost ($/Mcfe)(2)	$ 0.52	$ 0.41	$ 0.42
Natural Gas Systems			
Net Production:			
Natural Gas (Bcf)	35	33	36
Average Sales Price(1):			
Natural Gas ($/Mcf)	$ 3.00	$ 1.80	$ 1.15

(1) Includes costs associated with transporting volumes sold and the effects of our hedging program.

(2) Includes direct lifting costs (labor, repairs and maintenance, materials and supplies) and the administrative costs of field offices, insurance and property and severance taxes.

Acquisition, Development and Exploration Expenditures

The following table details information regarding Production's costs incurred in its development, exploration and acquisition activities for each of the three years ended December 31:

Production	2001	2000	1999
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 91	$ 201	$ 157
Unproved	44	171	187
Development Costs	1,529	1,229	766
Exploration Costs:			
Delay Rentals	14	12	11
Seismic Acquisition and Reprocessing	37	64	108
Drilling	126	214	170
Total	$1,841	$1,891	$1,399
Canada			
Acquisition Costs:			
Proved	$ 232	$ 3	$ —
Unproved	16	6	10
Development Costs	105	69	5
Exploration Costs:			
Delay Rentals	—	—	—
Seismic Acquisition and Reprocessing	10	10	5
Drilling	9	32	6
Total	$ 372	$ 120	$ 26
Other Countries[(1)]			
Acquisition Costs:			
Proved	$ —	$ —	$ —
Unproved	26	—	—
Development Costs	14	—	—
Exploration Costs:			
Delay Rentals	—	—	—
Seismic Acquisition and Reprocessing	6	18	5
Drilling	97	17	2
Total	$ 143	$ 35	$ 7
Worldwide			
Acquisition Costs:			
Proved	$ 323	$ 204	$ 157
Unproved	86	177	197
Development Costs	1,648	1,298	771
Exploration Costs:			
Delay Rentals	14	12	11
Seismic Acquisition and Reprocessing	53	92	118
Drilling	232	263	178
Total	$2,356	$2,046	$1,432

(1) Includes international operations in Australia, Brazil, Hungary, Indonesia and Turkey.

Excluded from the table above is $15 million of costs in 2001 attributable to Natural Gas Systems.

Regulatory and Operating Environment

Production's natural gas and oil activities are regulated at the federal, state and local levels, as well as internationally by the countries around the world in which Production does business. These regulations include, but are not limited to, the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. Production is also subject to governmental safety regulations in the jurisdictions in which it operates.

Production's U.S. operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of pollution resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. Production's international operations are subject to environmental regulations administered by foreign governments, which include political subdivisions and international organizations. These domestic and international laws and regulations relating to the protection of the environment affect Production's natural gas and oil operations through their effect on the construction and operation of facilities, drilling operations, production or the delay or prevention of future offshore lease sales. We believe that our operations are in compliance with the applicable requirements. In addition, we maintain insurance on behalf of Production for sudden and accidental spills and oil pollution liability.

Production's business has operating risks normally associated with the exploration for and production of natural gas and oil, including blowouts, cratering, pollution and fires, each of which could result in damage to life or property. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain insurance coverage on behalf of Production with respect to potential losses resulting from these operating hazards. However, insurance is not available to Production against all operational risks.

Markets and Competition

The natural gas and oil business is highly competitive in the search for and acquisition of additional reserves and in the sale of natural gas, oil and natural gas liquids. Production's competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms and quality of service. Ultimately, our future success in the production business will be dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

Field Services Segment

Our Field Services segment provides customers with wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and natural gas liquids. It also provides well-ties and real-time information services, including electronic wellhead gas flow measurement.

Field Services' assets include natural gas gathering and natural gas liquids pipelines, treating, processing and fractionation facilities in the San Juan Basin and the Rocky Mountain region, referred to as the Western Division; in the producing regions of east and south Texas, Mid-Continent, Permian Basin and the Gulf of Mexico, referred to as the Central Division; and in Louisiana, referred to as the Eastern Division.

A subsidiary in our Field Services segment serves as the general partner of El Paso Energy Partners and owns a one percent general partner interest and 26 percent of the partnership's common units. Field Services also owns preferred units of the partnership that have a $143 million liquidation value. As the general partner, Field Services manages the partnership's daily operations and strategic direction. Employees of Field Services perform all of the partnership's administrative and operational activities under a management agreement or, in some cases, separate operational agreements. El Paso Energy Partners provides gathering, transportation, fractionation, storage and other related activities for producers of natural gas, natural gas liquids and oil.

El Paso Energy Partners owns or has interests in natural gas and oil pipeline systems, offshore platforms, natural gas storage facilities, producing oil and natural gas properties, natural gas liquids gathering and transportation pipelines, fractionation plants and a natural gas processing plant.

The following tables provide information on Field Services' natural gas gathering and transportation facilities, its processing facilities and the facilities of its equity method investees:

Gathering & Treating	Ownership Interest	Miles of Pipeline[1]	Throughput Capacity[2]	Average Throughput[2] 2001	2000	1999
	(Percent)		(MMcfe/d)		(BBtue/d)	
Central Division[3]	100	11,140	5,383	4,086	1,701	1,073
Eastern Division	100	2,640	1,318	491	835	1,184
Western Division	100	7,375	1,635	1,532	1,332	1,686
El Paso Energy Partners	27	874	934	530	774	698

Processing Plants	Ownership Interest	Inlet Capacity[2]	Average Inlet Volume[2] 2001	2000	1999	Average Natural Gas Liquids Sales[2] 2001	2000	1999
	(Percent)	(MMcfe/d)		(BBtue/d)			(Mgal/d)	
Eastern Division[4]	100	3,115	1,801	1,671	393	1,782	1,917	595
Central Division[3]	100	1,890	1,830	516	411	3,463	774	598
Western Division	100	854	729	743	717	1,877	1,973	1,931
Aux Sable[5]	14	302	192	—	—	—	—	—
Mobile Bay[6]	42	441	146	338	115	—	—	—
Coyote Gulch	50	120	106	87	97	—	—	—

(1) Mileage amounts are approximate for the total systems and have not been reduced to reflect Field Services' net ownership.

(2) All volumetric information reflects Field Services' net interest.

(3) The Central Division includes our acquisition of PG&E's Texas Midstream operations in December 2000. In February 2002, we announced our plan to sell 9,400 miles of intrastate pipelines and 1,300 miles of gathering systems to El Paso Energy Partners.

(4) Reflects the acquisition of TransCanada Gas Processing U.S.A. in December 1999.

(5) Aux Sable went in service in December 2000.

(6) Mobile Bay went in service in April 1999.

Regulatory Environment

Some of Field Services' and El Paso Energy Partners' operations are subject to regulation by the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each entity subject to the FERC's regulation operates under separate FERC approved tariffs with established rates, terms and conditions of service.

Some of Field Services' and El Paso Energy Partners' operations are also subject to regulation by the Railroad Commission of Texas under the Texas Utilities Code and the Common Purchaser Act of the Texas Natural Resources Code. Field Services and El Paso Energy Partners file the appropriate rate tariffs and operate under the applicable rules and regulations of the Railroad Commission.

In addition, some of Field Services' and El Paso Energy Partners' operations, owned directly or through equity investments, are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act and the National Environmental Policy Act. Each of the pipelines has a continuing program of inspection designed to keep all of the facilities in compliance with pollution control and pipeline safety requirements, and Field Services and El Paso Energy Partners believe that these systems are in compliance with applicable requirements.

Markets and Competition

Field Services competes with major interstate and intrastate pipeline companies in transporting natural gas and natural gas liquids. Field Services also competes with major integrated energy companies, independent natural gas gathering and processing companies, natural gas marketers and oil and natural gas producers in gathering and processing natural gas and natural gas liquids. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling activity, service and access to favorable downstream markets.

Corporate and Other Operations

Through our corporate group, we perform management, legal, accounting, financial, tax, consulting, administrative and other services for our operating business segments. The costs of providing these services are allocated to our business segments.

Our other operations include the assets and operations of our telecommunication business, which involves providing wholesale transport services, primarily to metropolitan areas in Texas, and operating a facility that provides customers with fiber access and interconnectivity in Chicago, Illinois.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 14, and is incorporated herein by reference.

Employees

As of March 12, 2002, we had approximately 14,180 full-time employees, of which 889 are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of February 28, 2002, are listed below. Prior to August 1, 1998, all references to El Paso refer to positions held with El Paso Natural Gas Company.

Name	Office	Officer Since	Age
William A. Wise	Chairman, President, and Chief Executive Officer of El Paso	1983	56
H. Brent Austin	Executive Vice President and Chief Financial Officer of El Paso	1992	47
Ralph Eads	Executive Vice President of El Paso and President of El Paso's Merchant Energy Group	1999	42
Joel Richards III	Executive Vice President of El Paso	1990	55
John W. Somerhalder II	Executive Vice President of El Paso and President of El Paso's Pipeline Group	1990	46
Peggy A. Heeg	Executive Vice President and General Counsel of El Paso	1997	42
Greg G. Jenkins	Executive Vice President of El Paso	1996	44
Rodney D. Erskine	President of El Paso Production	2001	57
Byron R. Kelley	President of El Paso Energy International	2001	54
Robert G. Phillips	President of El Paso Field Services	1995	47
Clark C. Smith	President of El Paso Merchant Energy North America	2000	47
William A. Smith	President of El Paso Global LNG	1999	57

Mr. Wise has been Chief Executive Officer since January 1990 and the Chairman of the Board of Directors since January 2001. He was also Chairman of the Board from January 1994 until October 1999. Mr. Wise became the President of El Paso in July 1998 and also served in that capacity from January 1990 to April 1996. Mr. Wise is a member of the Board of Directors of Praxair, Inc. and is the Chairman of the Board of El Paso Tennessee Pipeline Co. and El Paso Energy Partners Company, the general partner of El Paso Energy Partners L.P.

Mr. Austin has been an Executive Vice President since May 1995. He has been our Chief Financial Officer since April 1992. Prior to that period, he served in various positions with Burlington Resources Inc. and Burlington Northern Inc. Mr. Austin is a member of the Board of Directors of El Paso Tennessee Pipeline Co. and El Paso Energy Partners Company, the general partner of El Paso Energy Partners, L.P.

Mr. Eads has been an Executive Vice President since July 1999 and President of the El Paso Merchant Energy Group since January 2001. Mr. Eads was a Managing Director and Co-Head of the Energy Group at Donaldson, Lufkin & Jenrette from January 1996 through June 1999. Prior to that period, he was Managing Director, Head of Energy at S.G. Warburg & Company.

Mr. Richards has been an Executive Vice President since December 1996. From January 1991 until December 1996, he was a Senior Vice President of El Paso. Mr. Richards is a member of the Board of Directors of El Paso Tennessee Pipeline Co.

Mr. Somerhalder has been an Executive Vice President of El Paso since April 2000, and President of our Pipeline segment since January 2001. He has been Chairman of the Board of TGP, EPNG, and SNG since January 2000. He was President of TGP from December 1996 to January 2000, President of El Paso Energy Resources Company from April 1996 to December 1996 and a Senior Vice President of El Paso from August 1992 to April 1996.

Ms. Heeg has been Executive Vice President and General Counsel of El Paso since January 1, 2002. She was Senior Vice President and Deputy General Counsel from April 2001 to December 2001 and Vice

President and Associate General Counsel for regulated pipelines from 1997 to 2001. Ms. Heeg has held various positions in the legal department of Tenneco Energy and El Paso since 1996. Ms. Heeg is a member of the Board of Directors of El Paso Tennessee Pipeline Co.

Mr. Jenkins has been Executive Vice President of El Paso since January 2002. He was President of El Paso Global Networks from August 2000 to January 2002. He was President of Merchant Energy from December 1996 to August 2000. He was Senior Vice President and General Manager of Entergy Corp. from May 1996 to December 1996. Prior to that period, he was President and Chief Executive Officer of Hadson Gas Services Company.

Mr. Erskine has been President of El Paso Production since our merger with Coastal in January 2001. He was Senior Vice President of Coastal from August 1997. He has held various positions with Coastal Oil & Gas Corporation, a subsidiary of Coastal, since 1994.

Mr. Kelley has been President of El Paso International since January 2001. He was Executive Vice President of Business Development and commercial management for El Paso International since 1996. Prior to that period, Mr. Kelley held various positions with Tenneco Energy.

Mr. Phillips has been President of El Paso Field Services since June 1997. He was President of El Paso Energy Resources Company from December 1996 to June 1997, President of Field Services from April 1996 to December 1996 and was a Senior Vice President of El Paso from September 1995 to April 1996. Prior to that period, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc. Mr. Phillips is a member of the Board of Directors of El Paso Energy Partners Company, the general partner of El Paso Energy Partners, L.P.

Mr. Clark C. Smith has been President of El Paso Merchant Energy North America since August 2000. He served as President and CEO of Engage Energy Inc. since 1997. Prior to that period, he held the position of President and CEO of Coastal Gas Marketing Company and held several positions with Enron Corp.

Mr. William A. Smith has been President of El Paso Global LNG since March 2001. He was an Executive Vice President of El Paso from October 1999 to March 2001. He was Executive Vice President and General Counsel of Sonat Inc. from 1995 to September 1999. He was Vice Chairman of Sonat Exploration from 1994 to 1995 and Chairman and President of SNG from 1989 to 1994.

Executive officers hold offices until their successors are elected and qualified, subject to their earlier removal. Each of these elected officers also hold offices and/or director positions with our affiliated entities.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions that do not materially detract from the value of these properties or our interests therein, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 14, and is incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our common stock is traded on the New York Stock Exchange and the Pacific Exchange under the symbol EP. As of March 12, 2002, we had 55,069 stockholders of record. This does not include individual participants who own our common stock, but whose shares are held by a clearing agency, such as a broker or bank.

The following table reflects the quarterly high and low sales prices for our common stock based on the daily composite listing of stock transactions for the New York Stock Exchange and the cash dividends we declared in each quarter:

	High	Low	Dividends
		(Per share)	
2001			
First Quarter	$75.3000	$57.2500	$0.2125
Second Quarter	71.1000	49.9000	0.2125
Third Quarter	54.4800	38.0000	0.2125
Fourth Quarter	54.0500	36.0000	0.2125
2000			
First Quarter	42.3125	30.3125	0.2060
Second Quarter	52.5000	39.3750	0.2060
Third Quarter	67.5000	46.2500	0.2060
Fourth Quarter	74.2500	57.1300	0.2060

In January 2002, our Board of Directors declared a quarterly dividend of $0.2175 per share of common stock, payable on April 3, 2002, to stockholders of record on March 1, 2002. Future dividends will be dependent upon business conditions, earnings, our cash requirements and other relevant factors.

We have an odd-lot stock sales program available to stockholders who own fewer than 100 shares of our common stock. This voluntary program offers these stockholders a convenient method to sell all of their odd-lot shares at one time without incurring any brokerage costs. We also have a dividend reinvestment and common stock purchase plan available to all of our common stockholders of record. This voluntary plan provides our stockholders a convenient and economical means of increasing their holdings in our common stock. Neither the odd-lot program nor the dividend reinvestment and common stock purchase plan have a termination date; however, we may suspend either at any time. You should direct your inquiries to Fleet National Bank, our exchange agent at 1-877-453-1503.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2001	2000	1999	1998	1997
	(In millions, except per common share amounts)				
Operating Results Data:[1]					
Operating revenues[2]	$57,475	$48,915	$27,325	$23,773	$27,819
Merger-related costs and asset impairments[3]	1,843	125	557	15	50
Ceiling test charges[4]	135	—	352	1,035	—
Income from continuing operations before preferred stock dividends	67	1,236	257	176	804
Income from continuing operations available to common stockholders	67	1,236	257	170	787
Basic earnings per common share from continuing operations	0.13	2.50	0.52	0.35	1.60
Diluted earnings per common share from continuing operations	0.13	2.43	0.52	0.34	1.58
Cash dividends declared per common share[5]	0.85	0.82	0.80	0.76	0.73
Basic average common shares outstanding	505	494	490	487	492
Diluted average common shares outstanding	516	513	497	495	497

	As of December 31,				
	2001	2000	1999	1998	1997
	(In millions)				
Financial Position Data:[1]					
Total assets[2]	$ 48,171	$46,320	$32,090	$26,759	$26,424
Long-term debt and other financing obligations	12,816	11,603	10,021	7,691	7,067
Non-current notes payable to unconsolidated affiliates	368	343	—	—	—
Company-obligated preferred securities of consolidated trusts	925	925	625	625	—
Minority interests	3,088	2,782	1,819	374	380
Stockholders' equity	9,356	8,119	6,884	6,913	7,203

(1) Our operating results and financial position data reflect the acquisitions of PG&E's Texas Midstream operations in December 2000 and DeepTech International in August 1998. These acquisitions were accounted for as purchases, and therefore operating results are included in our results prospectively from the purchase date.

(2) Our operating revenues and total assets reflect the significant growth in our Merchant Energy operations during 2001 and 2000 as well as the consolidation of the U.S. operations of Coastal Merchant Energy in September 2000.

(3) Our 2001 costs relate primarily to our merger with Coastal, and our 1999 costs relate primarily to our merger with Sonat.

(4) Ceiling test charges are reductions in earnings that result when capitalized costs of natural gas and oil properties exceed the upper limit, or ceiling, on the value of these properties.

(5) Cash dividends declared per share of common stock represent the historical dividends declared by El Paso for all periods presented.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

Over the past several years, our business activities and operations have grown dramatically as a result of significant acquisitions, transactions, and internal growth initiatives that have enhanced our ability to compete in the global energy industry. This growth has significantly expanded our operating scope, our ability to generate operating cash flows and our needs for cash for investment opportunities. Consequently, we have substantially expanded our credit facilities and entered into other financing arrangements and facilities to meet our needs during this period. The more significant events are discussed below.

Merger with The Coastal Corporation

In January 2001, we merged with The Coastal Corporation. We accounted for the merger as a pooling of interests and converted each share of Coastal common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We also exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. We issued a total of 271 million shares, including 4 million shares issued to holders of Coastal stock options. Our discussion and analysis of our financial condition and results of operations reflects the combined information of our two companies for all periods presented.

In connection with a Federal Trade Commission (FTC) order related to this merger, in 2001 we sold our Gulfstream pipeline project and Midwestern Gas Transmission system and our investments in the Empire State, Stingray, U-T Offshore and Iroquois pipeline systems. Proceeds from these sales were approximately $279 million and we recognized an extraordinary gain of $26 million, net of income taxes of $27 million, on these transactions.

Purchase of Texas Midstream Operations

In December 2000, we completed our purchase of Pacific Gas & Electric's (PG&E's)Texas Midstream operations for $887 million, including $527 million of assumed debt. We accounted for this acquisition as a purchase. The assets acquired consist of 7,500 miles of intrastate natural gas transmission and natural gas liquids pipelines that transport approximately 2.8 Bcf/d, nine natural gas processing plants that process 1.5 Bcf/d and rights to 7.2 Bcf of natural gas storage capacity. These assets serve a majority of the metropolitan areas and the largest industrial load centers in Texas, as well as numerous natural gas trading hubs. These assets also create a physical link between our EPNG and TGP systems. Results from this acquisition are reflected in our results of operations from the date of purchase.

In December 2000, to comply with an FTC order, we sold our interest in Oasis Pipeline Company. Proceeds from the sale were $22 million, and we recognized an extraordinary loss of $19 million, net of income taxes of $9 million.

In March 2001, we sold some of the acquired natural gas liquids transportation and fractionation assets to El Paso Energy Partners for approximately $133 million. The assets sold included more than 600 miles of natural gas liquids gathering and transportation pipelines and three fractionation plants located in south Texas. In February 2002, we announced the sale of the remaining natural gas transmission assets to El Paso Energy Partners. See a further discussion of this sale under our discussion of the segment operating results for the Field Services segment.

Merger with Sonat Inc.

In October 1999, we completed our merger with Sonat, Inc. We accounted for the merger as a pooling of interests and converted each share of Sonat common stock into one share of our common stock. We issued approximately 110 million shares. In connection with an FTC order related to this merger, we sold our East Tennessee Natural Gas Company and Sea Robin Pipeline Company pipeline systems as well as our one-third interest in the Destin Pipeline Company system. Proceeds from the sales were approximately $616 million, and we recognized an extraordinary gain of $89 million, net of income taxes of $59 million.

Balance Sheet Enhancement Plan

In December 2001, we announced a plan to strengthen our capital structure and enhance our liquidity in response to changes in market conditions in our industry. This plan involves the sale of assets, a reduction in capital spending, the issuance of equity and the elimination or renegotiation of the rating triggers for several of our financing arrangements. The goal of the plan is to reduce our debt to total capital ratio to 50 percent by the end of 2002. For further information about this plan, see the discussion under *Future Liquidity*.

Merger-Related Costs, Asset Impairments and Other Charges

Below are the charges incurred that had a significant impact on our results of operations, financial position and cash flows for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
Merger-related costs	$1,684	$ 93	$515
Asset impairments	159	32	42
Total merger-related costs and asset impairments	1,843	125	557
Changes in accounting estimates	317	—	—
	2,160	125	557
Ceiling test charges	135	—	352
	$2,295	$125	$909

Merger-Related Costs. Our merger-related costs relate to our mergers with Coastal and Sonat and consisted of the following for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
Employee severance, retention and transition costs	$ 840	$ 31	$303
Transaction costs	70	60	62
Business and operational integration costs	382	—	31
Merger-related asset impairments	163	—	78
Other	229	2	41
	$1,684	$ 93	$515

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following the Coastal merger, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. Following the Sonat merger, a total of approximately 870 full-time positions were eliminated in a similar restructuring. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of these restructurings. Retention charges include payments to employees who were retained following the mergers and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. The pension and post-retirement benefits were accrued on the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid.

Also included in the 2001 employee severance, retention and transition costs was a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock on the date of the Coastal merger in exchange for the fair value of Coastal employees' and directors' stock options.

Transaction costs include investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete our mergers. All of these items were expensed in the periods in which they were incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments, such as lease termination and abandonment charges, recognition of the mark-to-market value of energy trading contracts resulting from changes in how these contracts are managed under our combined operating strategy and incremental fees under software and seismic license agreements. Also included in the 2001 charges are approximately $222 million in estimated lease related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas and from El Paso, Texas to Colorado Springs, Colorado. These charges were accrued at the time we completed our relocations and closed these offices. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed as incurred.

Merger-related asset impairments relate to write-offs or write-downs of capitalized costs for duplicate systems, redundant facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following our merger with Coastal. These charges occurred in our Merchant Energy, Production and Pipelines segments, and all of these assets have either had their operations suspended or continue to be held for use. The charges taken were based on a comparison of the cost of the assets to their estimated fair value to the ongoing operations based on this change in operating strategy.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of our merger with Coastal and other miscellaneous charges. These items were expensed in the period in which they were incurred.

Asset Impairments. The 2001 asset impairment charges resulted from the write-downs of our investments in several international power projects in our Merchant Energy segment and several telecommunications investments in our Corporate and Other operations. The 2000 charges consisted of the impairment of coal mining and refining assets in our Merchant Energy segment and a gas processing facility in our Field Services segment. The 1999 charge occurred in the Pipeline segment and was derived from impairments of regulatory assets that were not recoverable based on the settlement of a rate case. The impairments in all periods were primarily a result of weak or changing economic conditions causing permanent declines in the value of these assets, and the charges taken for all assets were based on a comparison of each asset's carrying value to its estimated fair value based on future estimated cash flows. These assets continue to be held for use, or their operations have been suspended.

Changes in Accounting Estimates. Our 2001 changes in accounting estimates consist of $232 million in additional environmental remediation liabilities, $47 million of additional accrued legal obligations and a $38 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. These changes were primarily the result of several events that occurred as part of and following our merger with Coastal, including the consolidation of numerous operating locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These changes were also a direct result of a fire at our Aruba refinery. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. These charges are included as operating expenses in our income statement and reduced our net income before extraordinary items and net income for the year ended December 31, 2001, by approximately $215 million.

Ceiling Test Charges. Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. During the third quarter of 2001, capitalized costs exceeded this ceiling limit by $135 million, including $87 million for our Canadian full cost pool, $28 million for our Brazilian full cost pool and $20 million for other international production operations, primarily in Turkey. These charges were based on the November 1, 2001 daily posted oil and natural gas sales prices. During 1999, we incurred charges related to our U.S. full cost pool of $352 million based on end of period natural gas and oil prices. The natural gas and oil prices used in both periods were adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. These non-cash write-downs are included in our income statement as ceiling test charges.

We use financial instruments to hedge against volatility of natural gas and oil prices. The impact of these hedges was considered in the determination of our ceiling test charge during 2001, and will be factored into future ceiling test calculations. Had the impact of our hedges not been included in calculating our 2001 ceiling test charge, the charge would not have materially changed since we do not significantly hedge our international production activities.

Also as mentioned above, our 2001 charge was computed based on daily posted prices on November 1, 2001. Had we computed this charge based on the daily oil and natural gas prices as of September 30, 2001, the charge would have been approximately $275 million, including approximately $227 million for our Canadian full cost pool and $48 million for our Brazilian and other international production operations, including the impact on future cash flows of our hedging program. Had the impact of our hedging program been excluded, the charges would have been approximately the same for our international full costs pools and production operations, but we would have incurred an additional charge of approximately $576 million related to our U.S. full cost pool.

Results of Operations

Our results of operations, along with the impact, by segment, of the merger-related, asset impairment and other charges discussed above, extraordinary items and accounting changes for each of the three years ended December 31 were as follows:

	2001			2000			1999		
EBIT by Segment	Reported	Charges	Pro-forma[1]	Reported	Charges	Pro-forma[1]	Reported	Charges	Pro-forma[1]
Pipelines	$ 1,038	$ 334	$ 1,372	$ 1,323	$ —	$ 1,323	$1,200	$ 90	$1,290
Merchant Energy	897	378	1,275	929	21	950	261	67	328
Production	920	208	1,128	609	—	609	(85)	383	298
Field Services	195	56	251	214	11	225	130	8	138
Segment EBIT	3,050	976	4,026	3,075	32	3,107	1,506	548	2,054
Corporate and other	(1,429)	1,319	(110)	(57)	93	36	(287)	361	74
Consolidated EBIT	1,621	2,295	3,916	3,018	125	3,143	1,219	909	2,128
Interest and debt expense	(1,155)	—	(1,155)	(1,040)	—	(1,040)	(776)	—	(776)
Minority interest	(217)	—	(217)	(204)	—	(204)	(93)	—	(93)
Income taxes	(182)	(636)	(818)	(538)	(38)	(576)	(93)	(246)	(339)
Extraordinary items[2]	26	(26)	—	70	(70)	—	—	—	—
Accounting changes	—	—	—	—	—	—	(13)	13	—
Net income	$ 93	$1,633	$ 1,726	$ 1,306	$ 17	$ 1,323	$ 244	$ 676	$ 920

(1) Pro-forma amounts should not be used as a substitute for amounts reported under generally accepted accounting principles. They are presented solely to improve the understanding of the impact of the charges reported during the periods presented.

(2) In 2001, these gains were a result of FTC ordered sales in connection with our Coastal merger, including the sales of our Gulfstream pipeline project and Midwestern Gas Transmission system and our investments in the Empire State, Stingray, U-T Offshore and Iroquois pipeline systems. In 2000, these gains were a result of FTC ordered sales in connection with our Sonat merger, including the sales of our East Tennessee and Sea Robin pipeline systems.

Segment Results

Our four segments: Pipelines, Merchant Energy, Production and Field Services are strategic business units that offer a variety of different energy products and services, each requiring different technology and marketing strategies. We evaluate our segment performance based on earnings before interest expense and income taxes, or EBIT. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of sales) provides a more accurate and meaningful basis for analyzing operating results for the trading and refining portions of Merchant Energy and for the Field Services segment. For a further discussion of the individual segments, see the discussion of our businesses beginning on page 1, as well as Item 8, Financial Statements and Supplementary Data, Note 18.

Below is a discussion and analysis of the operating results of each of our business segments. These results include the impact of the merger-related costs, asset impairments and other charges discussed above for all years presented.

Pipelines

Our Pipelines segment operates our interstate pipeline businesses. Each pipeline system operates under a separate tariff that governs its operations, terms and conditions of service and rates. Operating results for our pipeline systems have generally been stable because the majority of the revenues are based on fixed reservation charges. As a result, we expect changes in this aspect of our business to be primarily driven by regulatory actions, system expansions and contractual events. Commodity or throughput-based revenues account for a smaller portion of our operating results. These revenues vary from period to period, and system to system, and are impacted by factors such as weather, operating efficiencies, competition from other pipelines and fluctuations in natural gas prices. Results of operations of the Pipelines segment were as follows for each of the three years ended December 31:

	2001	2000	1999
	(In millions, except volume amounts)		
Operating revenues	$ 2,748	$ 2,741	$ 2,756
Operating expenses	(1,866)	(1,599)	(1,703)
Other income	156	181	147
EBIT	$ 1,038	$ 1,323	$ 1,200
Throughput volumes (BBtu/d)[(1)]			
TGP	4,405	4,354	4,253
EPNG and MPC	4,535	4,310	3,954
ANR	3,776	3,807	3,515
CIG and WIC	2,341	2,106	1,847
SNG	1,877	2,132	2,077
Equity investments (our ownership share)	2,171	2,040	2,062
Total throughput	19,105	18,749	17,708

(1) Throughput volumes exclude those related to pipeline systems sold in connection with FTC orders related to our Coastal and Sonat mergers including the Midwestern Gas Transmission, East Tennessee Natural Gas and Sea Robin systems; and the Destin, Empire State and Iroquois pipeline investments. Throughput volumes exclude intrasegment activities.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Operating revenues for the year ended December 31, 2001, were $7 million higher than the same period in 2000. The increase was due to higher reservation revenues on the EPNG system as a result of a larger portion of its capacity sold at maximum tariff rates versus the same period in 2000 and the impact of completed system expansions and new storage and transportation contracts on ANR and CIG during 2001. Also contributing to the increase were the impact of higher natural gas prices in the first and second quarters on sales of segment-owned production, sales of excess natural gas and sales under regulated natural gas sales contracts, as well as higher throughput from increased deliveries to California and other western states. These increases were partially offset by lower 2001 revenues resulting from contract remarketing on the TGP system in late 2000 and the impact of the sales of the Midwestern Gas Transmission system in April 2001, Crystal Gas Storage in September 2000 and the East Tennessee Natural Gas and Sea Robin systems in the first quarter of 2000. Also partially offsetting the increase were lower 2001 sales of base gas from abandoned storage fields, the favorable resolution of natural gas price-related contingencies on CIG in 2000, lower transportation revenues in 2001 on TGP as a result of higher proportion of short versus long hauls compared to 2000 and lower remarketed rates on seasonal turned-back capacity in 2001 as a result of SNG's 2000 rate case settlement allowing some customers to partially reduce their firm transportation capacity.

Operating expenses for the year ended December 31, 2001, were $267 million higher than the same period in 2000 primarily as a result of the merger-related and other charges in 2001 discussed previously. Also contributing to the increase was the impact of higher natural gas prices in the first half of 2001 on natural gas purchase contracts, higher purchase gas costs due to the net impact of a natural gas imbalance revaluation in 2001 as a result of falling gas prices during the second half of the year, increases to our reserve for bad debts as a result of our exposure in connection with the bankruptcy of Enron Corp., and a one-time favorable adjustment to depreciation expense during the first quarter of 2000 as a result of approval by the FERC to reactivate the Elba Island LNG facility. Partially offsetting the increase were lower operating and maintenance expenses due to cost efficiencies following the merger with Coastal and reduced operating and depreciation expenses due to the sales of the Midwestern Gas Transmission system in April 2001, Crystal Gas Storage in September 2000 and East Tennessee and Sea Robin in the first quarter of 2000.

Other income for the year ended December 31, 2001, was $25 million lower than the same period in 2000 due to lower 2001 equity earnings on our Australian pipelines and Citrus Corp., which owns the Florida Gas Transmission System, and gains from the sales of non-pipeline assets in 2000. Also contributing to the decrease was the impact on equity earnings due to the sales of our investments in the Empire State and Iroquois pipeline systems in 2001 and the sale of our one-third interest in Destin Pipeline Company in 2000. Partially offsetting the decrease was increased earnings from our investment in the Alliance pipeline project which commenced operations in the fourth quarter of 2000.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Operating revenues for the year ended December 31, 2000, were $15 million lower than the same period in 1999. The decrease was due to the impact of our sales of the East Tennessee Natural Gas and Sea Robin systems in the first quarter of 2000 to comply with an FTC order related to our merger with Sonat, the favorable resolution of regulatory issues in the first quarter of 1999 on TGP and lower rates following SNG's May 2000 rate case settlement. Also contributing to the decrease was the impact of customer settlements and contract terminations in 2000 and resolutions of customer imbalance issues in 1999 on TGP. Partially offsetting the decrease were higher revenues from transportation and other services provided on each of our transmission systems due to improved average throughput in 2000 versus 1999, higher realized prices on pipeline gas sales in 2000, the favorable resolution of natural gas price-related contingencies in 2000 on CIG, and revenues from the January 2000 acquisition of Crystal Gas Storage which was sold in September 2000 to El Paso Energy Partners.

Operating expenses for the year ended December 31, 2000, were $104 million lower than the same period in 1999. The decrease was due to cost efficiencies following our merger with Sonat, lower operating costs due to the sales of East Tennessee and Sea Robin in the first quarter of 2000 and a one-time favorable adjustment to depreciation expense during the first quarter of 2000 as a result of approval by the FERC to reactivate the Elba Island facility. Also contributing to the decrease was the expense associated with the resolution of a contested rate matter with a customer of EPNG, severance and termination charges incurred as a result of our Sonat merger and the impairment of several SNG expansion projects, all occurring in 1999. Additionally, an increase in estimated future environmental costs and write-offs of duplicate information technology assets in 1999 on SNG following our merger with Sonat contributed to the decrease. The decrease was partially offset by higher gas costs related to the Dakota gasification facility, higher system balancing requirements and the impact of unfavorable producer and shipper settlements on EPNG.

Other income for the year ended December 31, 2000, was $34 million higher than the same period in 1999. The increase was due to higher earnings on Citrus Corp. as a result of a one-time benefit recorded in 2000, higher earnings from our equity investments in 2000 as well as gains on the sale of non-pipeline assets in the third quarter of 2000. The increase was partially offset by the favorable settlement of a regulatory issue in 1999, the elimination of an asset for the future recovery of costs of the Elba Island facility and a lower allowance for funds used during construction as a result of less expansion and construction activity in 2000.

Merchant Energy

Our Merchant Energy segment is involved in a wide range of activities in the wholesale energy markets, including asset ownership, customer origination, marketing and trading and financial services. Each of the markets served by Merchant Energy is highly competitive and is influenced directly or indirectly by energy market economics. Prior to October 2000, Coastal conducted its marketing and trading activities through Engage Energy U.S., L.P. and Engage Canada, L.P., a joint venture between Coastal and Westcoast Energy Inc., a major Canadian natural gas company. During the fourth quarter of 2000, Coastal terminated the Engage joint venture and commenced its own marketing and trading activities.

Asset Ownership

Merchant Energy's asset ownership activities include domestic and international power plants, refining, chemical and coal mining operations, and an emerging LNG business. In its power asset business, Merchant Energy owns or has interests in 95 plants in 20 countries. The segment's domestic power activities are principally conducted through Chaparral Investors, L.L.C., an unconsolidated affiliate in which Merchant Energy has a 20 percent ownership interest.

Chaparral. In 1999, we formed Chaparral. Through its subsidiaries, Chaparral (also referred to as Electron) owns domestic power assets and is funded with third party capital (80%) and El Paso capital (20%). We manage the daily activities of Chaparral's assets and investments and are paid an annual management fee. The basic strategy of Chaparral is:

- to acquire power facilities with attractive power contracts;
- to develop facilities that will operate under long-term tolling agreements;
- to restructure the power sales, fuel supply and credit agreements of PURPA facilities;
- to monetize these restructured arrangements to fund operations and grow the venture; and
- to operate these facilities in a fully deregulated environment in a manner that enhances their value.

Chaparral was formed in order to obtain low cost financing to grow new business activities and to generate a stable fee-based income stream. Merchant Energy's annual management fee is equal to 20% of the net present value of the assets of Chaparral and must be approved by the third party investor. This net present value, or NPV, represents the present value of anticipated future cash flows of Chaparral's assets, net of its liabilities, less the estimated cost to liquidate all third party capital. As of December 31, 2001, Chaparral held assets with a NPV totaling approximately $925 million.

As of December 31, 2001, Chaparral's total assets were $2.5 billion and its liabilities were $1.6 billion. Total third party capital in Chaparral was approximately $1.15 billion, of which the debt component was $1.0 billion. In order to lower the cost of the debt, we provided a contingent equity support arrangement on this debt. Under this arrangement, we issued mandatorily convertible preferred stock with an aggregate liquidation value of $1.0 billion to a trust we control. We could be required to sell this stock to repay the third party debt if, among other things, our credit ratings fall below investment grade and our stock price falls below $27.07 for ten consecutive trading days. We plan to amend this arrangement by eliminating the stock price/credit downgrade events and replace it with an El Paso financial guarantee in connection with our balance sheet enhancement plan. See a further discussion of our balance sheet enhancement plan under *Future Liquidity*.

The future success of Chaparral will be dependent upon our ability to successfully restructure existing assets in Chaparral, as well as acquire additional power facilities. Chaparral may face increased competition in the future for properties and facilities that are increasingly complicated to acquire and restructure. In addition, if not renegotiated or renewed, the debt financing that supports Chaparral matures in the first quarter of 2003. While it is our intent to renew these agreements, there are no guarantees that the financial investors will continue to participate or that third party capital will be available for investment.

Merchant Energy conducts a variety of transactions with Chaparral and generates earnings in several ways, which includes a performance-based management fee, equity earnings from Chaparral's activities and margins on risk management activities where Merchant Energy serves as the commodity provider for many of Chaparral's fuel and power purchase contracts. Chaparral also reimburses Merchant Energy for general and administrative expenses incurred on its behalf. During 2001, Merchant Energy earned $147 million in management fees from Chaparral and was reimbursed $20 million for general and administrative expenses. It also recognized $75 million in equity earnings. For 2002, the management fee will increase to approximately $185 million as approved by Chaparral's third party investor in the fourth quarter of 2001. This management fee increase reflects the growth that has occurred in the Chaparral asset portfolio. Assumptions used in establishing the annual management fee include estimates of future energy prices, future demand for power, timing and terms of contract restructurings and future interest rates. These assumptions are based on a combination of quoted market prices and rates, models which project future market changes and anticipated demand, and other variables. Changes in these assumptions can impact the annual management fee from year to year and these changes can be material.

From time to time, we enter into transactions with Chaparral and its affiliates to sell power assets. Merchant Energy's fiduciary responsibilities under its management agreement with Chaparral require that these transactions be entered into at fair and reasonable values. To ensure fairness, significant transactions are evaluated and approved by the third party investor of Chaparral as well as our Board of Directors. During 2001, Chaparral acquired power assets from us with a fair value of $276 million. We did not recognize any gains or losses on these transactions.

International Power Assets and Gemstone. Internationally, Merchant Energy's power assets consist primarily of investments in joint ventures that construct and operate power facilities and other infrastructure assets around the world. In Brazil, these activities are conducted through Gemstone, an unconsolidated affiliate through which Merchant Energy plans to expand its power investments in that country. Gemstone was formed in 2001 with a third party investor primarily to generate low-cost funds for financing power plants in Brazil and to reduce risk through the introduction of third party equity. Total third party capital in Gemstone at December 31, 2001, was $1 billion, of which the debt component was $950 million. To lower the cost of this debt, we provided a contingent equity support arrangement. Under this arrangement, we issued mandatorily convertible preferred stock with an aggregate liquidation value of $950 million to a trust we control. We could be required to sell this stock to repay the debt if, among other things, our credit ratings fall below investment grade and our stock price falls below $36.16 for ten consecutive trading days. In addition, if not renegotiated or renewed, the debt financing that supports Gemstone matures in 2004. We plan to amend this arrangement by eliminating the stock price/credit downgrade events and replace it with an El Paso financial guarantee in connection with our balance sheet enhancement plan. See a further discussion of our balance sheet enhancement plan under *Future Liquidity*.

Brazil's power infrastructure has primarily been based on the use of hydroelectric power generation. The success of Gemstone in the future will be based on the demand for natural gas fired generation in Brazil, which may be significantly impacted by the availability of competing generation, such as hydroelectric power generation, which is less expensive to operate and more abundant. Furthermore, there are numerous risks in operating internationally which could impact Gemstone's ultimate success.

Earnings from Merchant Energy's international power activities, including Gemstone, are derived primarily through equity earnings from these investments and will be dependent on the ultimate success of privately owned power generation and infrastructure development in countries where Merchant Energy does business. During 2001, Merchant Energy recorded net equity earnings from Gemstone of $2 million.

Refining, Chemical, Coal Mining and LNG. In addition to its power business, Merchant Energy has refining, chemical and coal mining operations and an emerging global LNG operation. Results from Merchant Energy's refining and chemical operations are highly dependent on margin differentials between feedstocks, primarily crude oil and other petroleum products and market prices of the products produced, both of which can be highly volatile. In our coal business, results are driven by productivity of our mining operations along with the market prices of the coal produced. In 2001, Merchant Energy increased the scope of its activities in LNG, with full operations expected in 2003 and 2004. The success of this business will be based substantially on the worldwide supply of natural gas and demand for LNG which will depend on strong natural gas prices and LNG shipping and terminalling infrastructure.

Customer Origination, Marketing and Trading

Merchant Energy's customer origination, marketing and trading activities provide energy supply and risk management solutions for its customers and affiliates involving natural gas, power, crude oil, refined products, chemicals and coal. Merchant Energy assists its customers with energy supply aggregation, storage and transportation management and provides them with an array of risk management products. Merchant Energy also conducts a substantial energy trading business that executes proprietary trading strategies and manages the segment's risk across multiple commodities and over seasonally fluctuating energy demands using consistent methodologies. During 2001 and 2000, U.S. energy supply and demand resulted in substantial volatility in the energy markets that significantly impacted Merchant Energy's earnings.

Merchant Energy's customer origination, marketing and trading groups account for their activities using mark-to-market accounting. Under this accounting method, financial instruments, physical commodity positions and contractual energy-related transactions are recorded on the balance sheet and the income statement at their fair value at the time they are entered into. Subsequent to their inception, the transactions continue to be adjusted in the balance sheet and income statement for changes in their fair value until they are settled. Determining the fair value of these positions at inception and until settlement principally involves the use of actively quoted prices and, to a lesser degree, other valuation methods, including models that rely on actively quoted prices. Approximately 9% of the value of our mark-to-market portfolio is based on model valuations (i.e., not on active market quotes). Most of these models are options-based valuations and involve contracts related to physical assets. Examples of contracts that are generally valued using models include natural gas pipeline capacity, natural gas storage contracts and to a lesser extent power plant tolling agreements. Modeling allows us to value these contracts, as well as manage them more effectively, providing lower cost service to our customers, and to effectively measure and manage the risk associated with them on a daily basis. Almost all of the model-based valuations we employ are spread option valuations, such as location spread options (pipeline capacity), time spread options (natural gas storage capacity) and spark spread options (natural gas-fired power plant tolling). The price data underlying these models is based, in part, on market data and our estimates of future prices for periods which market data is limited. An important variable in these models is the volatility of the prices underlying the contracts and the correlation of the prices underlying the contracts. There is limited market price data related to correlations and volatilities although significant implicit data does exist. We use this implicit market data and historical data to determine volatilities and correlation for calculation of these models. We believe these calculations to be reliable predictors of value over time. In addition, Merchant Energy maintains a risk controls group that verifies all market price data for accuracy, independently of the marketing and trading groups and this group conducts these activities on both actively quoted and model-derived information. Further, to the extent there is uncertainty of the amounts we will ultimately realize from these transactions, we adjust the amounts we recognize as income until these uncertainties are resolved. These estimates are adjusted as assumptions change or as transactions move closer to settlement and better estimates become available.

As of December 31, 2001, the fair value of our trading-related price risk management activities was $1,295 million, and total margins generated from these activities during 2001 were $690 million.

The following table details the fair value of Merchant Energy's price risk management activities by year of maturity and valuation methodology. The amounts reflected as prices actively quoted are based on values determined by market quotes and other actively traded data, primarily NYMEX and other exchange-based information, including broker quotes. The amounts reflected as prices based on models and other valuation methods represent the fair value of contracts calculated based on internal models using the methods discussed above.

Fair Value of Trading Price Risk Management Contracts as of December 31, 2001

Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Prices actively quoted	$394	$349	$266	$102	$ 61	$1,172
Prices based on models and other valuation methods	39	76	47	(12)	(27)	123
Total net trading assets	$433	$425	$313	$ 90	$ 34	$1,295

A reconciliation of our 2001 trading activities is as follows (in millions):

Fair value of contracts outstanding at December 31, 2000	$ 2,200
Fair value of contracts settled during the period	(1,973)
Initial recorded value of new contracts	160
Change in fair value of contracts	678
Changes in fair value attributable to changes in valuation techniques	2
Other	228
Net change in contracts outstanding during the period	(905)
Fair value of contracts outstanding at December 31, 2001[1]	$ 1,295

(1) At December 31, 2001, net assets from non-trading price risk management activities were $426 million, and total net assets from all of our price risk management activities were $1,721 million.

The fair value of contracts settled during the period represents the amounts of traded contracts settled in cash, through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The initial recorded value of new contracts includes the fair value of origination transactions at the time the transaction is initiated. The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination, until their settlement or, if not settled, until the end of the period. Included in change in fair value of contracts during the year is a net loss of $109 million related to changes in the market values of contracts transferred to our trading portfolio as a result of a change in the manner in which these contracts were managed following the Coastal merger. Included in other is the effect of natural gas storage purchases and premiums paid on option contracts.

Financial Services

In the financial services area, Merchant Energy conducts energy financing activities through its ownership of EnCap and Enerplus. EnCap manages four separate oil and natural gas investment funds in the U.S. and serves as an investment advisor to one fund in Europe. EnCap also facilitates investment in emerging energy companies and earns a return from these investments. Enerplus, which was acquired in 2000, is a Canadian investment management company which conducts fund management activities similar to EnCap, but in Canada. Results from Merchant Energy's financial services activities are based on a combination of management fees and market based earnings on the investments held by these companies.

Below are Merchant Energy's operating results and traded volumes (excluding intrasegment transactions) and an analysis of those results for each of the three years ended December 31:

	2001	2000	1999
	(In millions, except volumes)		
Operating Results:			
Trading and refining gross margin	$ 1,554	$ 1,355	$ 843
Operating and other revenues	702	625	403
Operating expenses	(1,878)	(1,428)	(1,244)
Other income	519	377	259
EBIT	$ 897	$ 929	$ 261
Volumes (Excludes intrasegment transactions):			
Physical			
Natural Gas (BBtue/d)	9,230	7,768	6,713
Power (MMWh)	221,075	118,672	79,361
Crude oil and refined products (MBbls)	698,933	667,834	664,935
Coal (MTons)	10,343	9,834	8,980
Financial Settlements (Bbtue/d)	232,282	151,115	113,814

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Trading and refining gross margin consists of revenues from commodity trading and origination activities less the costs of commodities sold as well as revenues from refineries and chemical plants, less the cost of the feedstocks used in the refining and production processes. For the year ended December 31, 2001, these gross margins were $199 million higher than the same period in 2000. The increase was primarily due to higher trading margins in natural gas, power, crude oil and refined products as a result of increased trading volumes and price volatility as well as increased income from transactions originated during 2001. The increase in trading margins was partially offset by the negative margins in refining resulting from a fire at our Aruba facility in April 2001, the lease of our Corpus Christi refinery and related assets to Valero in June 2001, lower margins in heavy crude based refined products and lower margins and throughput at the Eagle Point refinery as a result of decreased demand for jet fuel following the events of September 11, 2001. Also offsetting this increase were reserves established as a result of the bankruptcy of Enron Corp. in December 2001.

Merchant Energy has conducted trading activities and held derivative positions with Enron Corp. and its subsidiaries. In December of 2001, Enron and certain of its subsidiaries sought protection from its creditors under Chapter 11 of the U.S. Bankruptcy Code. Following this filing, Merchant Energy terminated all contracts with the Enron subsidiaries that filed for bankruptcy. This resulted in the transfer of Merchant Energy's net derivative positions with Enron out of price risk management activities to accounts receivable. In addition, Merchant Energy established reserves on these receivables that it believes are adequate based on the amounts it expects to collect through the bankruptcy. In the first quarter of 2002, Merchant Energy asserted a claim against Enron on the cancelled contracts.

Merchant Energy is a provider of power and natural gas to the state of California. During the latter half of 2000 and continuing into the first half of 2001, California experienced sharp increases in wholesale power prices and natural gas prices due to energy shortages resulting, in part, from a combination of unusually warm summer weather followed by high winter demand, low gas storage levels, lower hydroelectric power generation and maintenance downtime of significant generation facilities. As a result, the two major California utilities, Southern California Edison and Pacific Gas & Electric, defaulted on payments to creditors and accumulated substantial under-collections from customers. This resulted in their credit ratings being downgraded in 2001 from investment grade to below investment grade, and in April 2001, Pacific Gas and Electric filed for bankruptcy. During 2001, we recognized revenues from Pacific Gas & Electric and Southern California Edison that we believe are appropriate based on their improving financial condition. This resulted in our recognition of income on a portion of these transactions during the fourth quarter based on improved credit exposure to customers in the state.

Operating and other revenues consist of revenues from domestic and international power generation facilities and investments, including our management fee from Chaparral, coal operations, and revenues from EnCap and the other financial services business of Merchant Energy. For the year ended December 31, 2001, operating and other revenues were $77 million higher than the same period in 2000. The increase resulted from higher management fees from Chaparral, higher revenues from EnCap and our other financial services due to growth in these businesses, and revenues from the CEBU power project, a Philippine project in which we acquired an additional interest and began consolidating during the first quarter of 2001. Offsetting the increase were revenues recorded in 2000 on our West Georgia power generation facility that was sold in the fourth quarter of 2000.

Operating expenses for the year ended December 31, 2001, were $450 million higher than the same period in 2000. The increase was primarily a result of merger-related costs and asset impairments associated with combining operations with Coastal, and changes in our estimates of environmental remediation costs, legal obligations and spare parts inventory usability. Also contributing to the increase were higher operating expenses resulting from the expansion of our operations in Europe, Mexico, Brazil, Singapore, our liquefied natural gas business and the consolidation of the CEBU power project. The increase also resulted from higher fuel costs at our refineries due to higher natural gas prices. All increases were partially offset by lower operating expenses resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001 and 2000 costs related to the West Georgia plant which was sold in the fourth quarter of 2000.

Other income for the year ended December 31, 2001, was $142 million higher than the same period in 2000. The increase was the result of marketing, agency and technical services fees related to the development of the Macaé power project in Brazil, and higher equity earnings from Chaparral and our investment in the Capital District Energy power facility resulting primarily from the completion of power contract restructurings. These increases were partially offset by lower earnings on an Argentine investment, gains from the sale of a portion of our East Asia Power project, and the sale of our interest in a Guatemala power project, all occurring in 2000. Also offsetting the increase was lower earnings from the Javelina project due to reduced margins.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Trading and refining gross margin for the year ended December 31, 2000, was $512 million higher than the same period in 1999. Trading margins increased due to significant price volatility in natural gas, power, crude oil and refined products markets that increased the value of our trading portfolio during 2000 versus 1999. Refining margins increased resulting from an increase in sales volumes, primarily due to expansion at our Aruba refinery, increased prices on refined products in 2000 and improved brokerage margins. Also contributing to the increase was higher income from transactions originated in 2000.

Operating and other revenues for the year ended December 31, 2000, were $222 million higher than the same period in 1999. The increase was due to asset management fees earned from Chaparral, which began operations during the fourth quarter of 1999, revenues on the West Georgia power project, a seasonal peaking facility that began operating in June 2000, and the consolidation of a Brazilian power project in the latter part of 1999. Revenues on our Manchief power project, which began operating in July 2000 and EnCap's financial services activities in 2000 also contributed to the increase.

Operating expenses for the year ended December 31, 2000, were $184 million higher than the same period in 1999. The increase is due to higher general and administrative expenses and project development costs relating to international projects in 2000 as well as higher repair and maintenance expense and fuel costs relating to increased volumes in our refining operations. Also contributing to the increase were fuel costs relating to our West Georgia power project, higher depreciation expense relating to our Rensselaer generating facility, which was acquired in 1999, and operating costs on the Manchief generation facility. These increases were partially offset by higher reimbursement in 2000 of general and administrative costs relating to Chaparral, a 1999 charge to eliminate a minority investor in Sonat's marketing joint venture following the Sonat merger, and 1999 asset writedowns and charges to consolidate accounting policies with those of Sonat following the merger.

Other income for the year ended December 31, 2000, was $118 million higher than the same period in 1999. The increase was due to higher earnings from CE Generation, a power project acquired in March 1999, the benefit realized from the formation of our East Asia Power joint venture in March 2000, and a gain from the sale of our interest in a Guatemala power generation facility. Also contributing to the increase were increased earnings from Engage prior to the termination of the joint venture and a gain recorded in 2000 from the sale of 49 percent of our Montreal paraxylene facility. These increases were partially offset by lower equity earnings from investments in various international projects, primarily our investment in East Asia Power in the Philippines.

Production

Production's operating results are driven by a variety of factors including its ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices, and operate at the lowest cost level possible. In 2002, Production expects to continue an active onshore and offshore development drilling program to capitalize on its land and seismic holdings. The estimated capital expenditures for Production in 2002 are $1.7 billion. Production will continue to pursue strategic acquisitions of production properties and the development of coal seam projects subject to acceptable return hurdles.

Production engages in hedging activities on its natural gas and oil production in order to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. This is achieved primarily through natural gas and oil swaps. During 2001, approximately 80 percent of the segment's overall production was hedged at fixed prices. Our hedging program is intended to hedge approximately 75 percent of our anticipated current year production, approximately 50 percent of our anticipated succeeding year production and a lesser percentage thereafter. Production's hedge positions are monitored and evaluated in an effort to achieve its earnings objectives and reduce the risks associated with spot-market price volatility.

In December 2001, we announced the sale of natural gas and oil properties in connection with our balance sheet enhancement plan. See a discussion of our plan in *Future Liquidity*.

Below are the operating results and analysis of these results for each of the three years ended December 31:

	2001	2000	1999
	(In millions, except volumes and prices)		
Operating Results:			
Natural gas	$ 2,005	$ 1,412	$ 931
Oil, condensate and liquids	320	255	166
Other	22	19	11
Total operating revenues	2,347	1,686	1,108
Transportation and net product costs	(97)	(78)	(47)
Total operating margin	2,250	1,608	1,061
Operating expenses	(1,331)	(995)	(1,147)
Other income (loss)	1	(4)	1
EBIT	$ 920	$ 609	$ (85)
Volumes and Prices:			
Natural gas			
Volumes (MMcf)	564,740	516,917	416,511
Average realized prices ($/Mcf)	$ 3.44	$ 2.62	$ 2.11
Oil, condensate and liquids			
Volumes (MBbls)	14,382	11,626	10,300
Average realized prices ($/Bbl)	$ 21.68	$ 21.82	$ 15.03

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Operating revenues for the year ended December 31, 2001, were $661 million higher than the same period in 2000. The increase was attributable to higher volumes and higher realized prices for natural gas and higher volumes for oil, condensate and liquids than 2000.

Transportation and net product costs for the year ended December 31, 2001, were $19 million higher than the same period in 2000 primarily due to higher transported volumes and costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the year ended December 31, 2001, were $336 million higher than the same period in 2000. The increase was due to full cost ceiling test charges of $135 million on international properties incurred in the third quarter of 2001, higher depletion expense in 2001 as a result of increased production volumes combined with higher capitalized costs in the full cost pool, merger-related costs and increased oilfield service costs in 2001. Also contributing to the increase were higher severance and other production taxes in 2001, resulting from higher production volumes and higher gas prices.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Operating revenues for the year ended December 31, 2000, were $578 million higher than the same period in 1999. The increase was due to increased volumes and higher realized prices for natural gas and oil, condensate and liquids.

Transportation and net product costs for the year ended December 31, 2000, were $31 million higher than the same period in 1999 primarily due to higher transported volumes and costs incurred to meet minimum production quantities under pipeline agreements.

Operating expenses for the year ended December 31, 2000, were $152 million lower than the same period in 1999. The decrease was due to full cost ceiling test charges of $352 million incurred in the first quarter of 1999, decreased 2000 labor costs as a result of an organizational restructuring following our Sonat merger and 1999 charges to retain Sonat's seismic data in our production operations as a result of the merger. These decreases were partially offset by higher 2000 depletion rates, higher production taxes and higher production costs.

Field Services

Our Field Services segment provides a variety of services for the midstream component of our operations, including gathering and treating of natural gas, processing and fractionation of natural gas, natural gas liquids and natural gas derivative products, such as butane, ethane, and propane. Field Services also serves as the general partner of El Paso Energy Partners, L.P.

Field Services attempts to balance its earnings from its operating activities through a combination of fixed-fee based and market-based services. A majority of Field Services gathering and treating operations earn margins from fixed-fee-based services. However, some of its operations earn margins from market-based rates. Revenues from these market-based rate services are the product of the market price, usually related to the monthly natural gas price index and the volume gathered.

Processing and fractionation operations earn a margin based on fixed-fee contracts, percentage-of-proceeds contracts and make-whole contracts. Percentage-of-proceeds contracts allow us to retain a percentage of the product as a fee for processing or fractionation service. Make-whole contracts allow us to retain the extracted liquid products and return to the producer a Btu equivalent amount of natural gas. Under our percentage-of-proceeds contracts and make-whole contracts, Field Services may have more sensitivity to price changes during periods when natural gas and natural gas liquids prices are volatile.

As the general partner of El Paso Energy Partners, we perform the partnership's daily operations and provide the strategic direction and performs all of its administrative and operational activities. We were reimbursed $34 million for these services during 2001. In addition, we recognized $47 million in equity earnings during 2001 from El Paso Energy Partners related to our general partner, common and preferred units ownership interests.

We often enter into transactions with El Paso Energy Partners and its affiliates to acquire or sell assets, and specific procedures have been instituted for evaluating these transactions to ensure that they are in the best interests of us and the partnership and are based on fair values. These procedures require our Board of Directors to evaluate and approve, as appropriate, transactions with the partnership. In addition, a special committee comprised of the general partner's independent directors evaluates the transactions on the partnership's behalf. This typically involves engaging an independent financial advisor and independent legal counsel to assist with the evaluation and to opine on its fairness.

During 2001, we sold several assets to the partnership, including transportation and fractionation assets we acquired from PG&E and an investment in Deepwater Holdings, an entity that owned several pipeline gathering systems in the Gulf of Mexico. During 2001, the partnership also acquired the rights to the Chaco processing facility from its previous owners. We currently lease this facility under an agreement that expires in October 2002. In 2000, we sold an intrastate pipeline system in Alabama and storage facilities in Mississippi to the partnership. Each of these transactions was evaluated and approved, as appropriate, by our Board of Directors and by the general partner's committee of independent directors. Proceeds from our sales of assets to the partnership were $344 million in 2001 and $197 million in 2000. The 2000 proceeds include $170 million of Series B preference units issued to us in exchange for the storage facilities. We recognized an after-tax gain on these sales of $13 million in 2001. No gain or loss was recognized on the sales in 2000.

In February 2002, as part of the balance sheet enhancement plan, we announced the sale of additional midstream assets to El Paso Energy Partners for total consideration of $750 million. The primary assets to be sold include:

- 9,400 miles of intrastate transmission pipelines;
- 1,300 miles of gathering systems in the Permian Basin; and
- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

Proceeds will be approximately $554 million in cash and approximately $6 million in El Paso Energy Partners common units, along with the partnership's interest in the Prince tension leg platform and a nine percent overriding royalty interest that the partnership holds in the Prince field that have a combined fair value estimated at $190 million. We expect to complete the transaction in March 2002. The sale of these assets is contingent upon receiving customary regulatory approvals and execution of definitive agreements. We do not anticipate a material gain or loss on these transactions.

In addition to Field Services, several of our other segments also enter into transactions with El Paso Energy Partners in the normal course of business for the sale of natural gas and for services such as transportation and fractionation, storage, processing and other types of operational services. These transactions are based on similar terms as transactions with non-affiliates.

Field Services' operating results and an analysis of those results are as follows for each of the three years ended December 31, 2001:

	2001	2000	1999
	(In millions, except volumes and prices)		
Gathering, treating and processing gross margin	$ 561	$ 437	$ 289
Operating expenses	(437)	(275)	(219)
Other income	71	52	60
EBIT	$ 195	$ 214	$ 130
Volumes and prices			
Gathering and treating			
Volumes (BBtu/d)	6,109	3,868	3,943
Prices ($/MMBtu)	$ 0.13	$ 0.16	$ 0.14
Processing			
Volumes (inlet BBtu/d)	4,360	2,930	1,521
Prices ($/MMBtu)	$ 0.15	$ 0.18	$ 0.16

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Total gross margin for the year ended December 31, 2001, was $124 million higher than the same period in 2000. The increase was primarily due to higher volumes as a result of our acquisition of PG&E's Texas Midstream operations in December 2000. Volumes also increased as a result of our acquisition of the Indian Basin processing plant in the second quarter of 2000 combined with an increase in Indian Basin's processing capacity in 2001. The increase in margin was partially offset by higher processing costs associated with the new processing arrangement with El Paso Energy Partners at the Chaco processing facility in the fourth quarter of 2001. For the year ended December 31, 2001, average gathering, treating and processing rates were lower compared to 2000 due primarily to the different mix of assets and contract terms resulting from the acquisition of PG&E's Texas Midstream operations.

Operating expenses for the year ended December 31, 2001, were $162 million higher than the same period in 2000. The increase was due to higher operating, depreciation and other expenses primarily resulting from the addition of PG&E's Texas Midstream operations, as well as merger-related costs related to FTC ordered sales of assets owned by El Paso Energy Partners, merger-related employee severance and relocation expenses and other merger charges and changes in our estimated environmental remediation liabilities in 2001.

Other income for the year ended December 31, 2001, was $19 million higher than the same period in 2000. The increase was primarily due to increased earnings from El Paso Energy Partners and a gain on the sale of our interest in Deepwater Holdings in October 2001, partially offset by lower 2001 equity earnings from Deepwater Holdings as a result of the sale. The increase was also partially offset by equity investment losses from our Mobile Bay and Aux Sable liquids processing facilities due to low natural gas liquids prices and a 2000 gain on the sale of our Colorado dry gathering system.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Total gross margin for the year ended December 31, 2000, was $148 million higher than the same period in 1999. The increase was a result of higher gathering and treating margins due to higher average gathering rates, predominantly in the San Juan Basin, which are substantially indexed to natural gas prices and higher average condensate prices. Our higher 2000 margin was partially offset by the sale of El Paso Intrastate Alabama, a gathering system in the coal-bed methane producing regions of Alabama, to El Paso Energy Partners in March 2000. Processing margins were also higher due to higher natural gas and natural gas liquids prices in 2000, our acquisition of the Indian Basin processing plant in the second quarter of 2000 and higher processing volumes due to the acquisition of gas processing and fractionation facilities located in Louisiana at the end of 1999.

Operating expenses for the year ended December 31, 2000, were $56 million higher than the same period in 1999 due to higher depreciation and amortization from assets transferred from El Paso Natural Gas to Field Services following a FERC order, the impairment of the Needle Mountain LNG processing facility in 2000 and higher expenses on Coastal's gas processing plants as a result of the acquisition of processing and fractionation assets located in Louisiana in 1999. The increase was partially offset by the impairment of gathering assets in 1999, lower costs for labor and benefits and cost recoveries from managed facilities.

Other income for the year ended December 31, 2000, was $8 million lower than the same period in 1999. The decrease was primarily due to net gains in 1999 from the sale of our interest in the Viosca Knoll gathering system to El Paso Energy Partners in June 1999, as well as lower equity earnings in 2000 following the sale of our interest in Viosca Knoll.

Corporate and Other Expenses, Net

Our Corporate and Other operations includes our general and administrative activities, as well as the operations of our telecommunications and other miscellaneous businesses. During 2001, there was a significant downturn in the telecommunications market. As a result, we refocused our telecommunications strategy and reduced our capital investment in this start-up business. Our current business strategy involves primarily the development of wholesale metropolitan transport services, primarily in Texas. At December 31, 2001, our investment in the telecommunications business was $555 million.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Corporate and Other expenses for the year ended December 31, 2001, were $1,372 million higher than the same period in 2000. The increase was primarily a result of merger-related charges in connection with our January 2001 merger with Coastal, costs associated with increased estimates of environmental remediation costs, legal obligations and usability of spare parts inventories and lower margins due to the sale of substantially all of our retail gas stations in 2001. Also contributing to our higher costs were operating losses associated with our telecommunications business during 2001 which were approximately $72 million.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Corporate and Other expenses for the year ended December 31, 2000, were $230 million lower than the same period in 1999. The decrease was primarily due to costs related to our merger with Sonat in 1999, partially offset by costs incurred in 2000 related to our merger with Coastal. Also offsetting the decrease were increased funding commitments to the El Paso Energy Foundation in 2000.

Interest and Debt Expense

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Interest and debt expense for the year ended December 31, 2001, was $115 million higher than the same period in 2000. The increase was a result of higher long-term and short-term borrowings and lower capitalized interest in 2001 for ongoing capital projects, investment programs and operating requirements.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Interest and debt expense for the year ended December 31, 2000, was $264 million higher than the same period in 1999 primarily due to increased borrowings under a combination of short-term and long-term programs to fund capital expenditures, acquisitions and other investing activities, higher average interest rates in 2000 and increased interest expense on borrowings from Chaparral in 2000. This increase was partially offset by an increase in interest capitalized.

Minority Interest

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Minority interest for the year ended December 31, 2001, was $13 million higher than the same period in 2000. Higher balances in minority interests as a result of the issuance of additional preferred interests in Clydesdale Associates L.P. and Topaz Investors L.L.C. (part of our Gemstone transaction) and a full year of costs on Clydesdale and El Paso Energy Capital Trust IV, were significantly offset by lower interest rates. Clydesdale and Capital Trust IV were formed in May 2000.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Minority interest for the year ended December 31, 2000, was $111 million higher than the same period in 1999 primarily due to a full year of costs associated with the preferred interest in Trinity River Associates, L.L.C., formed in June 1999. Also contributing to the increase were costs associated with a preferred interest in Clydesdale Associates, L.P. and distributions associated with preferred securities of El Paso Energy Capital Trust IV, both of which were formed in May 2000.

For a further discussion of our borrowing and other financing activities during the period, see *Securities of Subsidiaries and Minority Interests.*

Income Tax Expense

Income tax expense for the year ended December 31, 2001, was $182 million, resulting in an effective tax rate of 73 percent. Of this amount, $115 million related to non-deductible merger charges and changes in our estimate of additional tax liabilities. The majority of these estimated additional liabilities were paid in 2001 and are being contested by us. The effective tax rate excluding these charges was 27 percent. For the years ended December 31, 2000 and 1999, income tax expense was $538 million and $93 million, resulting in effective tax rates of 30 percent and 27 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent in all years were primarily a result of the following factors:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends;
- non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities;
- foreign income taxed at different rates;
- utilization of deferred credits on loss carryovers;
- non-deductible dividends on the preferred stock of a subsidiary;
- non-conventional fuel tax credits; and
- depreciation, depletion and amortization.

For a reconciliation of the statutory rate of 35 percent to the effective rates, see Item 8, Financial Statements and Supplementary Data, Note 6.

Liquidity and Capital Resources

General

During the year ended December 31, 2001, we generated over $9 billion of cash through a combination of cash from operations, the issuance of long-term debt and other financing obligations, and the issuance of equity. This cash was used for capital expenditures, acquisitions, other investing activities, long-term debt repayments, dividends and other financing activities. The following is a further discussion of our operating, investing and financing cash flows for the year ended December 31, 2001.

Cash From Operating Activities

Net cash provided by our operating activities was $4.1 billion for the year ended December 31, 2001, compared to $99 million for 2000. The increase was primarily due to growth in cash-based earnings during 2001, resulting from higher realized prices and volumes in our Production segment, along with physical liquidations of net derivative trading positions related to our price risk management activities. Partially offsetting these increases were cash payments in 2001 for charges related to the merger with Coastal and higher interest payments.

Cash From Investing Activities

Net cash used in our investing activities was $5.0 billion for the year ended December 31, 2001. Our investing activities principally consisted of additions to property, plant, and equipment, including expenditures for developmental drilling and expansion and construction projects. We had additions to joint ventures and investments in unconsolidated affiliates, primarily related to our investment in Gemstone along with our investments in five coal-fired power plants and international power companies located in Brazil and China. Our additions to investments also consisted of short-term notes from unconsolidated affiliates. These notes are primarily related to a subsidiary of Chaparral, and a significant portion of these notes were repaid during 2001. In August 2001, we completed our acquisition of Velvet Exploration Ltd., a Canadian exploration and development company, with properties located in the Foothills and Deep Basin areas of western Alberta Province, Canada, at a cost of approximately $230 million. Cash inflows from investment-related activities included proceeds from the sale of our Manchief power facility to Chaparral, our Midwestern Gas Transmission system, our Gulfstream pipeline project, and other property, plant and equipment assets, along with proceeds from the sale of substantially all of our retail gas stations in 2001. Additional cash inflows included the sale of our interests in the Empire State and Iroquois pipeline systems and the liquidation of a health management investment portfolio.

Cash From Financing Activities

Net cash provided by our financing activities was $1.3 billion for the year ended December 31, 2001. Cash provided from our financing activities included the issuance of long-term debt, other financing obligations and notes to unconsolidated affiliates primarily related to Gemstone. We also had issuances of common stock as a result of an equity offering in December 2001, and the exercise of employee stock options, as well as the issuance of preferred securities related to one of our consolidated subsidiaries associated with Gemstone. During 2001, we repaid short-term borrowings, other financing obligations, retired long-term debt and paid dividends. We also repaid notes to unconsolidated affiliates primarily related to Chaparral and Gemstone.

Our significant borrowing and repayment activities during 2001 are presented below. These amounts do not include borrowings or repayments on our short-term financing instruments with an original maturity of three months or less, including our commercial paper programs and short-term credit facilities.

Date	Company	Type	Interest Rate	Principal	Net Proceeds[(1)]	Due Date
				(In millions)		
Issuances						
2001						
January	El Paso CGP	Crude oil prepayment	Variable	$ 150	$150	2002
February	El Paso	Zero coupon convertible bonds[(2)]	4.00%	1,800	784	2021
February	SNG	Notes	7.35%	300	297	2031
March	El Paso	Eurobond	6.61%[(3)]	510	505	2006
May	El Paso	Notes	7.00%	500	496	2011
July	El Paso	Medium-term notes	7.80%	700	688	2031
October	El Paso CGP	Loan[(4)]	4.49%	240	240	2004
Jan.-Dec.	El Paso Production	Various	Various	100	100	2005-2006
Retirements						
2001						
January	El Paso Production	Crude oil prepayment	Variable	$ 150		2001
February	El Paso CGP	Long-term debt	Variable	135		2001
February	SNG	Long-term debt	8.875%	100		2001
February	El Paso CGP	Long-term debt	10.000%	85		2001
February	El Paso Tennessee	Long-term debt	9.875%	24		2001
May	El Paso	Long-term debt	9.000%	100		2001
July	El Paso	Long-term debt	6.625%	600		2001
July	El Paso	Long-term debt	Variable	100		2001
August	EPEC Corporation	Long-term debt	9.625%	13		2001
Jan.-Dec.	El Paso Field Services	Long-term debt	Various	347		2001
Jan.-Dec.	El Paso Production	Natural gas production payment	LIBOR + 0.372%	135		2001
Jan.-Dec.	El Paso CGP	Various	Various	103		2001

(1) Net proceeds were primarily used to repay short-term and long-term borrowings and for general corporate purposes.

(2) These debentures are convertible into 8,456,589 shares of our common stock which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate was equivalent to an initial conversion price of $94.604 per share of our common stock.

(3) In March 2001, we issued €550 million (approximately $510 million) of euro notes at 5.75% due 2006. To reduce our exposure to foreign currency risk, we entered into a swap transaction exchanging the euro note for a $510 million U.S. dollar denominated obligation with a fixed interest rate of 6.61% for the five-year term of the note.

(4) The loan is collateralized by the lease payments from Valero for our Corpus Christi refinery and related assets. The interest rate on the loan is the London Interbank Offered Rate (LIBOR) plus 1.425%. To reduce our exposure to interest rate risk, we entered into a swap transaction with a notional amount of $240 million exchanging LIBOR for a fixed rate of 3.07%. This transaction results in the payment of a fixed rate of 4.495% until the swap terminates in June 2003.

In December 2001, we issued 20.3 million shares of our common stock at a price of $42.50 per share. Net proceeds of approximately $863 million were used to retire short-term debt and for general corporate purposes.

Credit Facilities and Available Capacity

We use commercial paper programs to manage our short-term cash requirements. Under our programs we can borrow up to $3 billion through a combination of individual corporate, TGP and EPNG commercial paper programs of $1 billion each.

We maintain a 3-year, $1 billion, revolving credit and competitive advance facility under which we can conduct short-term borrowings and other commercial credit transactions. This facility expires in 2003 and El Paso CGP (formerly Coastal), EPNG and TGP are designated borrowers under the facility. In June 2001, we replaced an existing 364-day revolving credit facility with a renewable $3 billion, 364-day revolving credit and competitive advance facility. EPNG and TGP are also designated borrowers under this new facility. The interest rate on these facilities varies and was based on LIBOR plus 50 basis points at December 31, 2001. No amounts were outstanding under these facilities at December 31, 2001.

In connection with our acquisition of PG&E's Texas Midstream operations in December 2000, we established a $700 million short-term credit facility, under which $455 million was outstanding on December 31, 2000. In February 2001, we borrowed an additional $245 million under the facility. In two separate payments in March and June 2001, we repaid the outstanding balance of the credit facility, and the facility was terminated.

We also supplement our commercial paper program with other smaller short-term credit facilities, some of which were used by Coastal prior to our merger and which were terminated during the year.

In April 2001, we filed a shelf registration statement with the Securities and Exchange Commission to sell, from time to time, up to a total of $3 billion in debt securities, preferred and common stock, medium term notes, or trust securities. At December 31, 2001, we had approximately $920 million remaining from this shelf registration statement under which we issued additional securities in January 2002.

As of December 31, 2001, TGP had $200 million, and SNG had $100 million under shelf registration statements on file with the Securities and Exchange Commission.

The availability of borrowings under our credit and borrowing agreements is subject to specified conditions, which we believe we currently meet. These conditions include compliance with the financial covenants and ratios required by such agreements, absence of default under such agreements, and continued accuracy of the representations and warranties contained in such agreements. Our senior unsecured debt issues have been given investment grade ratings by Standard & Poor's and Moody's.

2002 Activities

In January 2002, we increased our shelf registration statement from $920 million to $1.10 billion and issued $1.10 billion aggregate principal amount of 7.75% medium term notes due 2032. Net proceeds of approximately $1.08 billion, net of issuance costs, were used to repay short-term borrowings and for general corporate purposes. This issuance used up the remaining capacity on our previous shelf registration statement. In February 2002, we filed a new shelf registration statement with the Securities and Exchange Commission that allows us to issue up to $3 billion. Under this registration statement we can issue a combination of debt, equity and other instruments, including trust preferred securities of El Paso Capital Trust II and El Paso Capital Trust III, trusts wholly owned by us. If we issue securities from these trusts, we will be required to issue full and unconditional guarantees on these securities.

Also in January 2002, we retired $100 million aggregate principal amount 7.85% notes and $215 million aggregate principal amount 7.75% notes. In March 2002, we retired $400 million of floating rate notes.

In January 2002, SNG filed a shelf registration statement increasing the amount of debt it can issue from $100 million to $300 million. In February 2002, SNG issued $300 million aggregate principal amount of 8.0% notes due 2032. Net proceeds of approximately $297 million, net of issuance costs, were used for general corporate purposes. This issuance used the remaining capacity on SNG's shelf registration statement.

Future Liquidity

We rely on cash generated from our internal operations as our primary source of liquidity. We supplement our internally generated cash through our commercial paper programs, available credit facilities, bank financings, the issuance of long-term debt, trust securities and equity securities. From time to time, we also use structured financial products. We expect that our future funding for working capital needs, capital expenditures, acquisitions, other investing activities, long-term debt repayments, dividends and other financing activities will continue to be provided from these sources.

Our cash from internal operations may change in the future due to a number of factors, some of which we cannot control, including the price we will receive for the products we sell and services we provide, the demand for our products and services, margin requirements resulting from significant increases or decreases in commodity prices, operational risks, and other factors. Our ability to draw upon our available credit facilities will be dependent upon our ability to comply with the conditions and requirements of our credit facilities, all of which we believe we currently meet. Funding from the capital markets for commercial paper, long-term debt or equity or other structured financial products may be impacted by lack of liquidity for our industry segment, a change in our credit rating or changes in market conditions. For a further discussion of our business risks, see Risk Factors.

In December 2001, we announced a plan to strengthen our capital structure and enhance our liquidity in response to the changes in market conditions. In January 2002, our Board of Directors approved this plan. The key elements of our plan are to raise approximately $2.25 billion or more in cash from sales of assets, reduce net capital spending to approximately $3.1 billion in 2002, increase our common equity through a combination of earnings and equity financings, and eliminate or renegotiate the rating triggers in our Chaparral and Gemstone investments and on our Trinity River and Clydesdale minority interest financing transactions. The goal of the plan is to reduce our debt to total capital ratio from 54.9 percent at December 31, 2001, to approximately 50 percent by the end of 2002. In December 2001, we issued 20.3 million shares of our common stock generating $863 million. We also expect to have firm sales agreements completed for more than half of the asset sales by the end of the first quarter 2002, the first step of which we accomplished in February 2002 with the announcement of the sale of midstream assets to El Paso Energy Partners for total consideration of approximately $750 million. Additional assets that have been evaluated and may possibly be included in our asset sale program include approximately $1 billion in exploration and production properties, various refining and chemical assets, coal mining assets and power facilities. The actual assets sold will depend on a number of factors including short-term market developments, the availability of qualified buyers and acceptability of any offers received. In addition, potential losses or write-downs in the value of these assets could occur. Any proposed offer will be evaluated and approved by a Committee of our Board of Directors prior to its completion. We intend to commence exchange offers to the existing note holders of Chaparral and Gemstone to eliminate the rating triggers and replace them with securities that have direct financial guarantees from us, and expect to complete these exchange offers in the second quarter of 2002. We also expect to commence our amendment process on the Trinity River and Clydesdale transactions early in 2002. For a discussion of the risks that may affect our balance sheet enhancement plan, see Risk Factors.

Contractual Obligations and Commercial Commitments

In the course of our business activities, we enter into a variety of contractual obligations and commercial commitments. Some of these result in direct obligations that are reflected in our balance sheet while others are commitments, some firm and some based on uncertainties, that are not reflected in our underlying financial statements.

Contractual Cash Obligations

The following table summarizes our contractual cash obligations by payment due date. Each of these obligations is discussed in further detail below (in millions):

		Payments Due by Period			
Contractual Cash Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Short-term cash obligations	$ 1,515	$1,515	$ —	$ —	$ —
Long-term cash obligations[(1)]	14,690	1,799	1,613	1,837	9,441
Obligations to affiliates	872	504	61	18	289
Securities of subsidiaries and minority interests[(2)]	4,013	400	2,230	1,000	383
Operating leases	677	115	181	122	259
Capital commitments and purchase obligations	2,751	1,094	378	314	965
Total contractual cash obligations	$24,518	$5,427	$4,463	$3,291	$11,337

(1) Our long-term cash obligations exclude $75 million in unamortized debt discounts as of December 31, 2001.

(2) The maturity schedule for these instruments is based on the expiration period of the underlying agreements.

Short-Term Cash Obligations

Our short-term contractual cash obligations as of December 31, 2001, were as follows (in millions):

Commercial paper	$1,265
Short-term credit facilities	111
Notes payable	139
	$1,515

We can borrow up to $3 billion under a combination of Corporate, TGP and EPNG commercial paper programs of $1 billion each. At December 31, 2001, the weighted average rate on commercial paper outstanding was 3.2%.

We also have short-term notes payable to banks of $139 million and short term credit facilities of $111 million.

Long-Term Cash Obligations

Our long-term cash obligations as of December 31, 2001, were as follows (in millions):

Unsecured notes and debentures	$12,448
Convertible debentures	827
Collateralized notes	240
FELINE PRIDES[sm]	460
Other financing obligations	715
	$14,690

Our unsecured notes and debentures consists of third-party debt issued in the normal course of our business activities. These notes are secured by our general credit and that of our subsidiaries. The interest rates on these instruments range from 5.75% to 10.75%, and maturity dates range from 2002 to 2037.

Our zero coupon convertible debentures have a maturity value of $1.8 billion, are due 2021 and have a yield to maturity of 4%. These debentures are convertible into 8,456,589 shares of our common stock, which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate is equal to a conversion price of $94.604 per share of our common stock.

In October 2001, we borrowed $240 million due 2004 under a loan agreement. The loan is collateralized by the lease payments from Valero under their lease of our Corpus Christi refinery.

In 1999, we issued a total of 18,400,000 FELINE PRIDES[sm] consisting of 17,000,000 Income PRIDES with a stated value of $25 and 1,400,000 Growth PRIDES with a stated value of $25. The Income PRIDES consist of a unit comprised of a Senior Debenture and a purchase contract under which the holder is obligated to purchase from us by no later than August 16, 2002 for $25 (the stated price) a number of shares of our common stock. The Growth PRIDES consist of a unit comprised of a purchase contract under which the holder is obligated to purchase from us by no later than August 16, 2002 for $25 (the stated price) a number of shares of our common stock and a 2.5% undivided beneficial interest in a three-year Treasury security having a principal amount at maturity equal to $1,000. Under the terms of the purchase contract in effect prior to our merger with Coastal, the number of shares of common stock the holder of a PRIDE received varied between 0.5384 and 0.6568 shares, depending on the price of Coastal's common stock.

As a result of our merger with Coastal, and under the terms of the purchase contract, the number of shares the holder of a PRIDE is entitled and required to receive upon settlement became fixed at 0.6622 shares of El Paso common stock. This will result in the issuance of approximately 12.2 million shares of El Paso common stock.

Our other financing obligations consist of crude oil prepayments received from third parties in exchange for our agreement to deliver a fixed quantity of crude oil to a specified delivery point in the future and a production payment received in exchange for delivery of a fixed quantity of natural gas from our future production. The agreements, by their terms, can only be settled through the delivery of the commodity. We have entered into commodity swaps to effectively lock-in the value of these commitments to the third party upon delivery of the commodity. It is our intention to negotiate a cash settlement of the crude oil prepayments on or prior to the delivery dates under the agreements. We will continue to deliver natural gas under the production payment agreement according to its terms, but consider these agreements to be financing arrangements. The carrying cost of the prepayments and the production payment are recognized as interest expense in our income statement.

Obligations to Affiliates

Our obligations to unconsolidated affiliates as of December 31, 2001, were as follows (in millions):

Gemstone	$346
Chaparral	458
Other	68
	$872

Gemstone. Our obligation to Gemstone consists of $346 million of debt securities which are payable on demand and carry a fixed interest rate of 5.25%.

Chaparral. Our obligation to Chaparral consists of $169 million of debt securities and $289 million of contingent interest promissory notes. The debt securities are payable on demand and carry a fixed interest rate of 7.443%. The contingent interest promissory notes carry a variable interest rate not to exceed 12.75% and mature in 2019 through 2021.

Other. Our other obligations to affiliates include a line of credit with an unconsolidated affiliate for $57 million, which had an interest rate of 5.27% and miscellaneous notes with several unconsolidated affiliates for $11 million which had an average interest rate of 2.45% at December 31, 2001.

Securities of Subsidiaries and Minority Interests

Over the past three years, we have entered into a number of transactions to finance our consolidated subsidiaries. In most cases, these have been accomplished through the sale of preferred interests in these entities, or through structured financial transactions that are collateralized by the assets of these subsidiaries. Total amounts outstanding under these programs at December 31, 2001, were as follows (in millions):

Consolidated trusts[1]	$ 925
Trinity River	980
Clydesdale	1,000
Preferred stock of subsidiaries	465
Gemstone	300
Consolidated partnership	285
Other	58
	$4,013

[1] The consolidated trusts are composed of Capital Trust I, Coastal Finance I and Capital Trust IV.

Capital Trust I. In March 1998, we formed El Paso Energy Capital Trust I which issued 6.5 million of 4¾% trust convertible preferred securities for $325 million. We own all of the Common Securities of Trust I. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4¾% convertible subordinated debentures due 2028, their sole asset. We provide a full and unconditional guarantee of Trust I's preferred securities. Trust I's preferred securities are reflected as company-obligated preferred securities of consolidated trusts in our balance sheet. Distributions paid on the preferred securities are included as minority interest in our income statement.

Trust I's preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of $4\frac{3}{4}$%, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I Preferred Security (equivalent to a conversion price of $41.59 per common share). As of December 31, 2001, we had approximately 6.5 million Trust I preferred securities outstanding.

Coastal Finance I. In May 1998, Coastal completed a public offering of 12 million mandatory redemption preferred securities on Coastal Finance I, a business trust, for $300 million. Coastal Finance I holds debt securities of ours purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375% of the liquidation amount of $25 per preferred security. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at our option on or after May 13, 2003, or earlier if various events occur. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption.

Capital Trust IV. In May 2000, we formed El Paso Energy Capital Trust IV which issued $300 million of preferred securities to a third party investor. These preferred securities pay cash distributions at a floating rate equal to the three-month LIBOR plus 75 basis points. As of December 31, 2001, the floating rate was 2.83%. These preferred securities must be redeemed by Trust IV no later than November 30, 2003. Proceeds from the sale of the securities were used by Trust IV to purchase a series of our floating rate senior debentures whose yield and maturity terms mirror those of Trust IV's preferred securities. The sole assets of Trust IV are these floating rate senior debentures. We provide a full and unconditional guarantee of all obligations of Trust IV related to its preferred securities. At the time Trust IV issued the preferred securities, we also agreed to issue $300 million of equity securities, including, but not limited to, our common stock in one or more public offerings prior to May 31, 2003.

Trinity River (also known as Red River). During 1999, we formed a series of companies that we refer to as Trinity River. Trinity River was formed to provide financing to invest in various capital projects and other assets. A third-party investor contributed cash of $980 million into Trinity River during 1999 in exchange for the preferred securities of one of our consolidated subsidiaries. The third party is entitled to an adjustable preferred return derived from Trinity River's net income. The preferred interest is collateralized by a combination of notes payable from us and various fixed assets, including our Mojave pipeline, Bear Creek Storage, various natural gas and oil production properties and some of our El Paso Energy Partners common units. We have the option to acquire the third-party's interest in Trinity River at any time prior to June 2004. If we do not exercise this option or if the agreement is not extended, we could be required to liquidate the assets supporting this transaction. We account for the investor's preferred interest in our consolidated subsidiary as a minority interest in our balance sheet and the preferred return as minority interest expense in our income statement. The assets, liabilities and operations of Trinity River are included in our financial statements. If our credit ratings are downgraded to below investment grade by both S&P and Moody's, we could be required to liquidate the assets supporting the transaction.

Clydesdale (also known as Mustang). During 2000, we formed a series of companies that we refer to as Clydesdale. Clydesdale was formed to provide financing to invest in various capital projects and other assets. A third-party investor contributed cash of $1 billion into Clydesdale in exchange for the preferred securities of one of our consolidated subsidiaries. The third party is entitled to an adjustable preferred return derived from Clydesdale's net income. The preferred interest is collateralized by a combination of notes payable from us and various fixed assets, including our Colorado Interstate Gas transmission system and natural gas and oil properties. We have the option to acquire the third-party's interest in Clydesdale at any time prior to May 2005. If we do not exercise this option or if the agreement is not extended, we could be required to liquidate the assets supporting this transaction. We account for the investor's preferred interest in our consolidated subsidiary as a minority interest in our balance sheet and the preferred return as minority interest expense in our income statement. The assets, liabilities, and operations of Clydesdale are included in our financial statements. If our credit ratings are downgraded to below investment grade by both S&P and Moody's, we could be required to liquidate the assets supporting the transaction.

El Paso Tennessee Preferred Stock. In 1996, El Paso Tennessee Pipeline Co., our subsidiary, issued 6 million shares of publicly registered 8.25% cumulative preferred stock with a par value of $50 per share for $300 million. The preferred stock is redeemable, at the option of El Paso Tennessee, at a redemption price equal to $50 per share, plus accrued and unpaid dividends, at any time after January 2002. During the three years ended December 31, 2001, dividends of approximately $25 million were paid each year on the preferred stock.

Coastal Securities Company Preferred Stock. In 1996, Coastal Securities Company Limited, our wholly owned subsidiary, issued 4 million shares of preferred stock for $100 million. Quarterly cash dividends are being paid on the preferred stock at a rate based on LIBOR. The preferred shareholders are also entitled to participating dividends based on various refining margins. Coastal Securities may redeem the preferred stock for cash at the liquidation price plus accrued and unpaid dividends.

Coastal Oil & Gas Resources Preferred Stock. In 1999, Coastal Oil & Gas Resources, Inc., our wholly owned subsidiary, issued 50,000 shares of preferred stock for $50 million. The preferred shareholders are entitled to quarterly cash dividends at a rate based on LIBOR. The dividend rate is subject to renegotiation in 2004 and on each fifth anniversary thereafter. In the event Coastal Oil & Gas Resources and the preferred shareholders are unable to agree to a new rate, Coastal Oil & Gas Resources must redeem the shares at $1,000 per share plus any accrued and unpaid dividends, or cause the preferred stock to be registered with the Securities and Exchange Commission and remarketed. Coastal Oil & Gas Resources also has the option to redeem all shares on any dividend rate reset date for $1,000 per share plus any accrued and unpaid preferred dividends.

Coastal Limited Ventures Preferred Stock. In 1999, Coastal Limited Ventures, Inc., our wholly owned subsidiary, issued 150,000 shares of preferred stock for $15 million. The preferred shareholders are entitled to quarterly cash dividends at an annual rate of 6%. The dividend rate is subject to renegotiation in 2004 and on each fifth anniversary thereafter. In the event Coastal Limited and the preferred shareholders are unable to agree to a new rate, the preferred shareholders may call for redemption of all of the preferred shares. The redemption price is $100 per share plus any accrued and unpaid preferred dividends thereon. Coastal Limited also has the option to redeem all shares on any rate reset date for $100 per share plus any accrued and unpaid preferred dividends.

Gemstone. As part of the Gemstone transaction, our wholly owned subsidiary, Topaz Investors, L.L.C., issued a minority member interest to the third party investor of Gemstone for $300 million. The third party investor is entitled to a cumulative preferred return of 8.03% on its interest. The agreements underlying this transaction expire in 2004, or earlier if we sell the international power assets owned indirectly by Topaz. The minority member interest is redeemable at liquidation value plus accrued and unpaid dividends.

Consolidated Partnership. In December 1999, Coastal Limited contributed assets to a limited partnership in exchange for a controlling general partnership interest. Limited interests in the partnership were issued to unaffiliated investors for $285 million. The limited partners are entitled to a cumulative priority return based on LIBOR. The return is subject to renegotiation in 2004 and on each fifth anniversary thereafter. The partnership has a maximum life of 20 years, but may be terminated sooner subject to certain conditions, including failure to agree to a new rate. Coastal Limited may terminate the partnership at any time by repayment of the limited partners' outstanding capital plus any unpaid priority returns.

Operating Leases

We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2002 until 2053. As of December 31, 2001, our total commitments under operating leases were approximately $677 million.

Under several of our leases, we have provided residual value guarantees to the lessor. Under these guarantees, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is typically equal to the outstanding loan amounts owed by the lessor, or we can choose to assist in the sale of the leased asset to a third party. Should the asset not be sold for a price that equals or exceeds the amount of the guarantee, we would be obligated for the shortfall. The levels of our residual value guarantees range from 86.0 percent to 89.9 percent of the original cost of the leased assets. For the total outstanding residual value guarantees on our operating leases at December 31, 2001, see *Residual Value Guarantees* below.

Capital Commitments and Purchase Obligations

At December 31, 2001, we had capital and investment commitments of $2.4 billion primarily relating to our production, pipeline, and international power activities. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures. We have entered into unconditional purchase obligations for products and services totaling $346 million at December 31, 2001. The annual obligations under these agreements are $34 million for 2002, $32 million for 2003, $34 million for each of the years 2004, 2005 and 2006, and $178 million in total thereafter.

Commercial Commitments

The following table summarizes our Commercial Commitments by date of expiration. Each of these commitments is discussed in further detail below:

	Total	Amount of Commitment Expiration Per Period			
Commercial Commitments	**Total Amounts Committed**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**Over 5 Years**
			(In millions)		
Lines of credit	$ 173	$ —	$ 173	$ —	$ —
Standby letters of credit	465	423	29	11	2
Guarantees	3,423	392	2,251	72	708
Residual value guarantees	738	77	—	—	661
Other commercial commitments	1,779	—	44	161	1,574
Total commercial commitments	$6,578	$892	$2,497	$244	$2,945

Lines of Credit

We have a commitment to loan Mesquite, a subsidiary of Chaparral and our affiliate, up to $725 million. As of December 31, 2001, Mesquite had borrowed $552 million under this facility, resulting in undrawn commitment of $173 million. The interest rate on the facility is based on LIBOR plus a margin, and was 2.64% at December 31, 2001.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2001, we had outstanding letters of credit of $465 million related to our marketing and trading activities, our domestic power development and other operating activities.

Guarantees

Our involvement in joint ventures and project level construction and finance results in the issuance of financial and non-financial guarantees in our business activities. We also guarantee performance and contractual commitments of companies within our consolidated group. There are various events and circumstances that may require us to perform under our guarantees, including:

- non-payment by the guaranteed party;
- non-compliance with the covenants of the transactions by the guaranteed party;
- non-compliance by us with the provision of guarantees; and
- cross-acceleration with other transactions.

As of December 31, 2001, we had approximately $1.5 billion of guarantees in connection with our international development and operating activities not consolidated on our balance sheet and approximately $1.9 billion of guarantees in connection with domestic development and operating activities not consolidated on our balance sheet. Of these amounts, approximately $950 million relates to our Gemstone investment and $1.0 billion relates to our Chaparral investment.

Residual Value Guarantees

As of December 31, 2001, we have $738 million of residual value guarantees supporting our operating leases. These leases expire in 2002 and 2006.

Other Commercial Commitments

From May to October 2001, we entered into agreements to time-charter four separate ships to secure transportation for our developing liquefied natural gas business. The agreements provide for deliveries of vessels between 2003 and 2005. Each time-charter has a 20-year term commencing when the vessels are delivered with the possibility of two 5-year extensions. The total commitment under the four time charter agreements is $1.8 billion.

Contingencies

For a discussion of our contingencies, see Item 8, Financial Statements and Supplementary Data, Note 14, incorporated herein by reference.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analogizing to similar situations and the accounting guidance governing them, and often consult with our independent accountants about the appropriate interpretation and application of these policies. Our critical accounting policies include policies that are related to specific business units, such as price risk management activities and accounting for oil and gas activities, as well as broad policies that include accounting for impairments and contingencies, consolidations and business combinations. Each of these areas involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

Critical Accounting Policies

Price Risk Management Activities. We account for price risk management activities based upon the fair value accounting methods prescribed by Emerging Issues Task Force (EITF) Issue 98-10 and SFAS No. 133. EITF Issue 98-10 governs the accounting for our energy trading activities while SFAS No. 133 prescribes our accounting for hedging activities and other derivatives. Both sets of accounting rules require that we determine the fair value of the instruments we use in these business activities and reflect them in our balance sheet at their fair values. However, changes in the fair value from period to period for our energy trading derivatives and fair value hedges are recorded in our income statement each period while changes in the fair value of our cash flow hedges are generally recognized in our income statement when the hedge is settled. Over time, these methods will derive similar results. However, from period to period, income under these methods can differ significantly.

One of the primary factors that can have an impact on our results each period is the price assumptions used to value our energy trading derivatives and fair value hedges. Many of these instruments have quoted market prices. However, we are required to use internal valuation techniques or models, particularly in our energy trading activities, to estimate the fair value of instruments that are not traded on an active exchange or that have terms that extend beyond the time period for which exchange-based quotes are available. These modeling techniques require us to estimate future prices, price correlation, interest rates and market volatility and liquidity. Our estimates also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instrument and the transaction being hedged, both at the inception and on an ongoing basis. This is complicated since energy commodity prices, the primary risk we hedge, have quality and locational differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Asset Impairments. The asset impairment accounting rules require us to determine if an event has occurred indicating that a long-lived asset may be impaired. In some cases, these events are clear. However, in many cases, a clearly identifiable triggering event does not occur. Rather, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated where we have investments in foreign countries or where we have projects where we are not the operator. Events can occur that may not be known until a later date from their occurrence. We continually monitor our businesses and the market and business environments and make judgments and assessments about whether a triggering event has occurred. If an event occurs, we make an estimate of our future cash flows from these assets to determine if the asset is impaired. For investments, we evaluate whether events and possible outcomes indicate that a decline in the value of our investment that is other than temporary has occurred, which also generally involves an assessment of project level cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors and these variables can, and often do, differ from our estimates. These changes can have either a positive or negative impact on our estimates of impairment and can result in additional charges. In addition, further changes in the economic and business environment can impact our original and ongoing assessments of potential impairment.

Accounting for Reserves. Our accounting for reserves policies cover a wide variety of business activities, including reserves for potentially uncollectible receivables, rate matters and legal and environmental exposures. We accrue these reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. Our estimates for these liabilities are based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon the outcome or expectations based on the facts surrounding each exposure.

Accounting for Natural Gas and Oil Producing Activities. We use the full-cost method of accounting for our natural gas and oil producing activities. Under this accounting method, we capitalize substantially all of the costs incurred in connection with the exploration, acquisition and development of natural gas and oil reserves in full cost pools maintained by geographic area, regardless of whether reserves are actually located. This method differs from the successful efforts method of accounting for these activities. The primary difference between these two methods is the treatment of exploratory dry hole costs, which are exploration, acquisition and development costs on wells that do not yield measurable reserves. Under the successful efforts method, these costs are generally expensed when the determination is made that measurable reserves will not be added. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher depletion rate.

Under the full cost accounting method, we conduct quarterly impairment tests of our capitalized costs in each of our cost pools based on an assessment of discounted cash flows. This test is referred to as a ceiling test. The two primary factors impacting this test are reserve levels and current prices. In addition, the prices we use in this assessment reflect the impact of our hedging programs. Our risks related to this test are changing estimates of natural gas and oil reserves and a decline in prices. The process of estimating natural gas and oil reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields increases the likelihood of significant changes in these estimates. The prices of natural gas and oil are volatile and change from period to period. We attempt to realize more determinable cash flows through the use of hedges, but a continued decline in commodity prices will impact the results of our ceiling test.

Accounting for Business Combinations. During the past three years, we have completed several significant business combination transactions. In the future, we may continue to grow our business through business combinations. Prior to the issuance of SFAS No. 141, *Business Combinations*, in 2001, we applied the guidance provided by Accounting Principles Board Opinion (APB) No. 16, and its interpretations, as well as various other authoritative literature and interpretations that address issues encountered in accounting for business combinations. We accounted for our past combinations using both the purchase and pooling of interests methods as was required prior to the issuance of SFAS No. 141, which only allows the use of the purchase method. The accounting for business combinations, whether by the purchase or pooling of interests method, is complicated and involves the use of significant judgment.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether it is in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. Determining the fair values of the assets and liabilities acquired involves the use of judgment, since the majority of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices, where available, appraisals, comparisons to transactions for similar assets and liabilities and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Under the pooling of interests method of accounting, a business combination is accounted for using the historical cost of the entities involved in the combination. The rules for the pooling of interests method of accounting are highly complex, and involve the application of interpretations that have evolved over the years since the original issuance of APB No. 16. Consequently, our accounting for business combinations under this method requires us to apply the existing accounting literature and interpretations to the specific situations encountered in each transaction. As a result, there is a risk that our judgments and interpretations could be viewed differently by others. In addition, even though our Coastal and Sonat mergers occurred prior to the effective dates of SFAS No. 141, we continue to take measures to ensure that these mergers continue to qualify under the pooling rules. If we were unable to account for our Coastal and Sonat mergers as poolings of interests, our financial statements would be materially different.

Principles of Consolidation. We currently have interests in joint ventures, equity investors and financing arrangements that, based on existing accounting guidance precludes us from consolidating these entities. In December 2001, Enron Corp., one of the largest companies in the energy industry, declared bankruptcy in what has been viewed as one of the largest bankruptcies in history. In the wake of this event, accounting standard setters, including the Securities and Exchange Commission, are evaluating the existing accounting and disclosure rules and requirements. One area that has received a high level of scrutiny is the accounting rules related to consolidations, specifically those that address special-purpose entities. Standard setting bodies and regulators are currently evaluating the consolidation rules to determine whether the existing accounting framework should change. In the future, there is risk that existing standards will change, particularly in light of the events of 2001, and that these changes could result in the consolidation in our financial statements of entities that we do not currently consolidate.

For further details on these and our other significant accounting policies, and the estimates, assumptions and judgments we use in applying these policies, see Item 8, Financial Statements and Supplementary Data, Note 1.

New Accounting Pronouncements Issued But not Yet Adopted

Business Combinations. In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations*. This Statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method and prohibits the use of the pooling of interests method for all business combinations initiated after June 30, 2001. This Statement also establishes specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off at the acquisition date as an extraordinary item. The accounting for any business combinations we undertake in the future will be impacted by this standard. The Statement also requires, upon adoption, that we write off to income any negative goodwill recognized on business combinations for which the acquisition date was before July 1, 2001, as the effect of a change in accounting principle. We do not expect the negative goodwill provisions of this pronouncement will have a material effect on our financial statements.

Goodwill and Other Intangible Assets. In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*. This Statement requires that goodwill no longer be amortized but periodically tested for impairment at least on an annual basis. An intangible asset with an indefinite useful life can no longer be amortized until its useful life becomes determinable. This Statement has various effective dates, the most significant of which is January 1, 2002. Upon adoption of this Statement on January 1, 2002, we will no longer recognize annual amortization expense of approximately $50 million on goodwill and indefinite-lived intangible assets. We do not expect the impairment provisions of this pronouncement will have a material effect on our financial statements.

Accounting for Asset Retirement Obligations. In August 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. This Statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this Statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

Accounting for the Impairment or Disposal of Long-Lived Assets. In October 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. This Statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this Statement are effective for fiscal years beginning after December 15, 2001. The provisions of this Statement will impact any asset dispositions we make after January 1, 2002.

Under our balance sheet enhancement plan, we anticipate that we will sell a variety of assets, including the previously announced sale of midstream assets to El Paso Energy Partners, and the potential sales of natural gas and oil properties and refining, chemical, coal mining and power assets. Should these sales occur, based on our current assessment of SFAS No. 144's provisions, our coal mining, chemical and refining assets are likely to qualify as discontinued operations under the standard. The other assets, including the announced sale of midstream assets would, we believe, qualify as assets held for sale. In addition, SFAS No. 144 establishes new rules when a company begins to take action to either dispose of, or otherwise alter the manner of operation of, an asset. Under these new rules, when it becomes "more likely than not" that a company will alter its current operating plans, an evaluation of possible impairment is made. Based on our announced actions to date, we are currently evaluating whether the assets we may sell are impaired under this standard. Based on preliminary indications of market value, coupled with the near-term outlook for the refining and coal mining industries, we anticipate that we may be required to write-down the carrying values of the refining and coal mining assets we may sell by an amount that could range from $145 million to $240 million after-tax under this standard. We continue to evaluate these and the other assets that may be sold under as part of our plan. See a further discussion of our balance sheet enhancement plan under *Future Liquidity*.

Derivatives Implementation Group Issue C-16. In September 2001, the Derivatives Implementation Group of the FASB cleared guidance on Issue C-16, *Scope Exceptions: Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract.* This guidance impacts the accounting for fuel supply contracts that require delivery of a contractual minimum quantity of a fuel other than electricity at a fixed price and have an option that permits the holder to take specified additional amounts of fuel at the same fixed price at various times. We use fuel supply contracts such as these in our power producing operations and currently do not reflect them in our balance sheet since they are considered normal purchases that are not classified as derivative instruments under SFAS No. 133. This guidance becomes effective in the second quarter of 2002, and we will be required to account for these contracts as derivative instruments under SFAS No. 133. We are currently evaluating the impact of this guidance on our financial statements.

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. All of our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the Commission from time to time and the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

The success of our pipeline and field services business depends on factors beyond our control.

Most of the natural gas and natural gas liquids we transport, gather, process and store are owned by third parties. As a result, the volume of natural gas and natural gas liquids involved in these activities depends on the actions of those third parties, and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current transmission, storage, gathering, processing, and sales volumes and rates, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity:

- future weather conditions, including those that favor hydroelectric generation or other alternative energy sources;
- price competition;
- drilling activity and supply availability;
- expiration of significant contracts; and
- service area competition.

The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.

Substantially all of our pipeline subsidiaries' revenues are generated under natural gas transportation contracts which expire periodically and must be renegotiated and extended or replaced. Although we actively pursue the renegotiation, extension and/or replacement of these contracts, we cannot assure you that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts.

In particular, our ability to extend and/or replace transportation contracts could be harmed by factors we cannot control, including:

- the proposed construction by other companies of additional pipeline capacity in markets served by our interstate pipelines;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts;
- reduced demand due to higher natural gas prices;

- the availability of alternative energy sources or supply points; and
- the viability of our expansion projects.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues and earnings.

Fluctuations in energy commodity prices could adversely affect our business.

If natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, especially Canada, our ability to compete with other transporters may be negatively impacted. Revenues generated by our transmission, gathering and processing contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and natural gas liquids. The success of our transmission, gathering and processing operations in the Gulf of Mexico is subject to continued development of additional oil and natural gas reserves in the vicinity of our facilities and our ability to access additional reserves to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission, gathering and processing through our offshore facilities. Fluctuations in energy prices, which may impact gathering rates and investments by third parties in the development of new natural gas and oil reserves connected to our gathering and processing facilities, are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;
- federal and state taxes, if any, on the sale or transportation of natural gas and natural gas liquids; and
- abundance of supplies of alternative energy sources.

If there are reductions in the average volume of the natural gas and natural gas liquids we transport, gather and process for a prolonged period, our results of operations and financial position could be significantly, negatively affected.

The rates we are able to charge our customers may be reduced by governmental authorities.

Our pipeline businesses are regulated by the FERC, Department of Transportation, Texas Railroad Commission and various state and local regulatory agencies. In particular, the FERC generally limits the rates we are permitted to charge our customers for interstate natural gas transportation and, in some cases, sales of natural gas. If the rates we are permitted to charge our customers for use of our regulated pipelines are lowered, or do not recover current cost levels, or if the terms and conditions of tariffs or contracts are modified, the profitability of our pipeline businesses may be reduced.

The success of our natural gas and oil exploration and production businesses is dependent on factors that are beyond our control.

The performance of our natural gas and oil exploration and production businesses is dependent upon a number of factors that we cannot control. These factors include:

- fluctuations in natural gas and crude oil prices including basis differentials;
- the results of future drilling activity;
- our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;

- our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive leasing conditions;
- risks incident to operations of natural gas and oil wells;
- future drilling, production and development costs, including drilling rig rates; and
- increased competition in the search for and acquisition of reserves.

Estimates of natural gas and oil reserves may change.

Actual production, revenues, taxes, development expenditures, and operating expenses with respect to our reserves will likely vary from our estimates of proved reserves of natural gas and oil, and those variances may be material. The process of estimating natural gas and oil reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir or deposit. As a result, these estimates are inherently imprecise. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves may vary substantially from our estimates. In addition, we may be required to revise the reserve information, downward or upward, based on production history, results of future exploration and development, prevailing natural gas and oil prices and other factors, many of which will be beyond our control.

The success of our power generation and marketing activities depends on many factors beyond our control.

The success of our international and domestic power projects and power marketing activities, and the amount of the related performance-based management fee paid to us in connection with Chaparral, could be adversely affected by factors beyond our control, including:

- alternative sources and supplies of energy becoming available due to new technologies and interest in self generation and cogeneration;
- uncertain regulatory conditions resulting from the ongoing deregulation of the electric industry in the United States and in foreign jurisdictions;
- our ability to negotiate successfully and enter into, restructure or recontract advantageous long-term power purchase agreements;
- the possibility of a reduction in the projected rate of growth in electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs;
- the inability of customers to pay amounts owed under power purchase agreements; and
- the increasing price volatility due to deregulation and changes in commodity trading practices.

The success of our refining and chemical activities depends on many factors beyond our control.

The success of our refining and chemical activities depends on many factors, many of which are beyond our control, including:

- availability of alternative sources of supply, including those from new refineries or foreign locations;
- ongoing regulations over and laws governing the sale and use of chemicals we produce;
- demand for our products and the impact of economic recession on markets for our products; and
- prices of feedstocks, primarily crude oil.

Our use of derivative financial instruments could result in financial losses.

Some of our subsidiaries use futures and option contracts traded on the New York Mercantile Exchange, over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. We could incur financial losses in the future as a result of volatility in the market values of the energy commodities we trade, or if one of our counterparties fails to perform under a contract. The valuation of these financial instruments can involve estimates. Changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices were to increase, or interest rates were to change. For additional information concerning our derivative financial instruments, see item 7A, Quantitative and Qualitative Disclosures About Market Risk and Item 8, Financial Statements and Supplementary Data, Note 8.

Attractive acquisition and investment opportunities may not be available.

Our ability to grow will depend, in part, upon our ability to identify and complete attractive acquisition and investment opportunities. Opportunities for growth through acquisitions and investments in joint ventures, and the future operating results and success of these acquisitions and joint ventures within and outside the United States may be subject to the effects of, and changes in United States and foreign:

- trade and monetary policies;
- laws and regulations;
- political and economic developments;
- inflation rates;
- taxes; and
- operating conditions.

In addition, there is increased competition for acquisition and investment opportunities. Increased competition could result in our not being the successful bidder or making an acquisition at a higher relative price than we have historically paid. Any of these occurrences would limit our ability to fully execute our growth strategy.

Our foreign operations and investments involve special risks.

Our activities in areas outside the U.S. are subject to the risks inherent in foreign operations, including:

- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, wars, insurrection and other political risks;
- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies and other economic problems; and
- changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties.

Costs of environmental liabilities, regulations and litigation could exceed our estimates.

Our current and former operations involve management of regulated materials and are subject to various environmental laws and regulations. These laws and regulations obligate us to clean up various sites at which petroleum, chemicals, low-level radioactive substances or other regulated materials may have been disposed of or released. Some of these sites have been designated Superfund sites by the EPA under the Comprehensive Environmental Response, Compensation and Liability Act. We are also party to legal proceedings involving environmental matters pending in various courts and agencies.

It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the difficulty of estimating clean up costs;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and

- the possible introduction of future environmental laws and regulations.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties. For additional information concerning our environmental matters, see Item 8, Financial Statements and Supplementary Data, Note 14.

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with those operations, including explosions, pollution, release of toxic substances, fires, hurricanes and adverse weather conditions and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. In addition, our operations face possible risks associated with acts of aggression on our domestic and foreign assets. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against these types of risks to the extent and in amounts that we believe are reasonable, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

We are subject to financing and interest rate exposure risks.

Our future success depends on our ability to access capital markets and obtain financing at cost effective rates. In addition, our trading business is heavily dependent on favorable credit ratings, a downgrade of which can trigger higher cash requirements and operating costs. Our ability to access financial markets and obtain cost-effective rates in the future are dependent on a number of factors, many of which we cannot control, including changes in:

- interest rates;
- tax rates due to new tax laws;
- the structured and commercial financial markets;
- market perceptions of us or the natural gas and energy industry;
- our stock price; and
- our credit ratings.

Our inability to amend the rating triggers in Chaparral's and Gemstone's third-party debt or otherwise refinance their debt could adversely impact our credit ratings.

We will face competition from third parties to transport, gather, process, fractionate, store or otherwise handle oil, natural gas, natural gas liquids and other petroleum products.

The oil and natural gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. Our competitors include the major oil companies, independent oil and gas concerns, individual producers, gas marketers and major pipeline companies, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. If we are unable to compete with services offered by other energy enterprises, which may be larger, offer more services, and possess greater resources, our future profitability may be negatively impacted.

We may not achieve all of the objectives set forth in our balance sheet enhancement program in a timely manner or at all.

Our ability to achieve all of the objectives of our balance sheet enhancement program, as well as the timing of their achievement, if at all, is subject to factors beyond our control, including:

- our ability to raise $2.25 billion in cash from asset sales may be impacted by our ability to locate potential buyers in a timely fashion and obtain a reasonable price or by competing asset sales programs by our competitors; in addition, even if we receive the cash amount announced under the enhancement program, there is no guarantee that the results of this program will be achieved; and
- our ability to amend the rating triggers on Chaparral's and Gemstone's third party debt is conditional upon the approval of the existing note holders and third party equity investors, our credit rating and perceptions of our company and industry.

Other factors impacting our timing and our ability to complete our enhancement program include our ability to issue equity securities which is based on our stock price, credit ratings and liquidity in the capital markets, and our ability to retain earnings which is based on operational factors, economic conditions and commodity prices.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We use derivative financial instruments to manage market risks associated with energy commodities, interest rates and foreign currency exchange rates. Our primary market risk exposures are to changing commodity prices. Our market risks are monitored by a corporate risk management committee to ensure compliance with our overall stated risk management policies as approved by the Audit Committee of our Board of Directors. This committee operates independently from the business segments that create or actively manage these risk exposures.

During 2001, we experienced a significantly changing energy market brought about by the energy crisis in California, the events of September 11th, the bankruptcy of Enron Corp., and a significant decline in energy commodity prices. We limited our market risk exposure during this period of market uncertainty by continually monitoring our net physical and financial positions and assuming minimal risk. We expect this continuous monitoring and reduced risk assumption to continue in the near term.

Trading Commodity Price Risk

Our Merchant Energy segment is exposed to market risks inherent in the financial instruments it uses for trading energy and energy related commodities. Merchant Energy records its energy trading activities, including transportation capacity, tolling agreements and storage contracts at fair value. Changes in fair value of these activities are reflected in our income statement. Merchant Energy's policy is to manage commodity price risks through a variety of financial instruments, including:

- exchange-traded futures contracts involving cash settlements;
- forward contracts involving cash settlements or physical delivery of an energy commodity;
- swap contracts which require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity;
- exchange-traded and over-the-counter options; and
- other contractual arrangements.

Merchant Energy measures the risk in its traded commodity and energy related contracts on a daily basis using a Value-at-Risk model to determine the maximum potential one-day unfavorable impact on its earnings, due to normal market movements, and monitors its risk in comparison to established thresholds. Since 1998, Merchant Energy has used what is known as the variance-covariance technique of measuring Value-at-Risk. This technique uses historical price movements and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of its assets and liabilities held for price risk management activities. This method works well for futures, forwards and swaps, but does not completely capture the risk of option positions, especially for large deviations from current underlying values. For this reason, Merchant Energy began measuring its Value-at-Risk using a historical simulation technique in December 2001. This technique fully values positions in every iteration of the simulation and captures risk from all types of positions, including options. Merchant Energy also uses other measures to provide additional assurance that the risks in its commodity and energy related contracts are being properly monitored on a daily basis, including sensitivity analysis, stress testing, credit risk management and the establishment of parameters to monitor and measure risk exposure, highlight unfavorable trends, and measure performance of the portfolio using applicable risk metrics.

The following table presents our potential one-day unfavorable impact on earnings before interest and income taxes as measured by Value-at-Risk for our traded commodity and energy related contracts and is prepared based on a confidence level of 95 percent and a one-day holding period. The high and low valuations represent the highest and lowest of the month end values during 2001. The average valuation represents the average of the 2001 month end values. Actual losses may exceed those measured by Value-at-Risk using either of the modeling techniques presented below:

Value-at-Risk Modeling Technique	Value-at-Risk 2001 Year end	High	Low	Average	2000 Year end
	(In millions)				
Trading Value-at-Risk					
Variance-covariance	$21	$45	$21	$33	$29
Historical simulation	$18	—	—	—	—
Portfolio Value-at-Risk[1]					
Historical simulation	$17	—	—	—	—

[1] Portfolio Value-at-Risk represents the combined Value-at-Risk for the trading and non-trading price risk management activities. The separate calculation of Value-at-Risk for trading and non-trading commodity contracts ignores the natural correlation that exists between traded and non-traded commodity contracts and prices. As a result, the individually determined values will be higher than the combined Value-at-Risk in most instances. We manage our risks through a portfolio approach that balances both trading and non-trading risks.

Non-trading Commodity Price Risk

Our segments are exposed to a variety of market risks in the normal course of their business activities. Our Production segment has market risks related to the oil and natural gas it produces. Our Field Services segment has market risks related to the natural gas and natural gas liquids it retains in its processing operations. The refining activities in our Merchant Energy segment are exposed to market risks in both the feedstocks they use, primarily crude oil and petroleum based products, as well as the refined products they sell. Our Merchant Energy segment has market risks from changing prices of natural gas between locations connected by transportation capacity on our pipelines. We attempt to mitigate market risk associated with these significant physical transactions through the use of non-trading financial instruments, including:

- exchange-traded futures contracts involving cash settlements;
- forward contracts involving cash settlements or physical delivery of an energy commodity;
- swap contracts which require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity; and
- exchange-traded and over-the-counter options.

The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments we use to mitigate these market risks that were outstanding at December 31, 2001 and 2000. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table.

	Fair Value	10% Increase Fair Value	10% Increase Increase (Decrease)	10% Decrease Fair Value	10% Decrease Increase (Decrease)
Impact of changes in commodity prices on derivative commodity instruments (in millions)					
December 31, 2001	$ 435	$ 286	$(149)	$ 570	$135
December 31, 2000	$(1,865)	$(2,188)	$(323)	$(1,561)	$304

In December 2001, we began measuring the risk associated with our commodity contracts held for non-trading purposes using Value-at-Risk determined using the historical simulation technique. Based on a confidence level of 95 percent and a one-day holding period, our estimated potential one-day unfavorable impact on earnings before interest and income taxes was $15 million at December 31, 2001.

Interest Rate Risk

Many of our debt related financial instruments, derivative contracts and project financing arrangements are sensitive to market fluctuations in interest rates. From time to time, we manage our exposure to interest rate risk through the use of non-trading derivative financial instruments, primarily through interest rate swaps.

As of December 31, 2001, we maintained an interest rate swap transaction with a notional amount of $240 million exchanging LIBOR, a variable interest rate, for a fixed rate of 3.07%. This transaction results in the payment of a fixed rate of 4.49% until the swap terminates in June 2003. The fair value of this swap was immaterial as of December 31, 2001.

The table below shows the maturity of the carrying amounts and related weighted average interest rates on our interest bearing securities, by expected maturity dates. As of December 31, 2001, the carrying amounts of short-term borrowings are representative of fair values because of the short-term maturity of these instruments. The fair value of the long-term debt has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2001								December 31, 2000	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
	(Dollars in millions)									
Liabilities:										
Short-term debt — variable rate	$1,515						$ 1,515	$ 1,515	$ 2,301	$ 2,301
Average interest rate	2.6%									
Long-term debt, including current portion — fixed rate	$ 738	$306	$726	$434	$ 996	$9,333	$12,533	$12,007	$10,991	$11,164
Average interest rate	8.2%	7.8%	7.0%	8.5%	6.4%	7.2%				
Long-term debt, including current portion-variable rate	$1,061	$279	$299	$131	$ 265	$ 47	$ 2,082	$ 2,082	$ 1,940	$ 1,959
Average interest rate	2.7%	5.1%	6.1%	6.0%	5.8%	5.8%				
Notes payable to unconsolidated affiliates — fixed rate	$ 436	$ 51	$ 10	$ 12	$ 6		$ 515	$ 539	$ 253	$ 276
Average interest rate	5.7%	7.4%	6.4%	6.4%	6.4%					
Notes payable to unconsolidated affiliates — variable rate	$ 68					$ 289	$ 357	$ 357	$ 486	$ 486
Average interest rate	4.9%					10.4%				
Company-obligated preferred securities:										
El Paso Energy Capital Trust I						$ 325	$ 325	$ 370	$ 325	$ 579
Average interest rate						4.8%				
El Paso Energy Capital Trust IV		$300					$ 300	$ 300	$ 300	$ 300
Average interest rate		4.8%								
Coastal Finance I						$ 300	$ 300	$ 378	$ 300	$ 293
Average fixed interest rate						8.4%				

Foreign Currency Exchange Rate Risk

Our exposure to foreign currency exchange rates relates to changes in foreign currency rates on our international power investments and operations, our foreign trading operations and foreign debt obligations that are not denominated or adjusted to U.S. dollars. From time to time, we manage this exposure to changes in foreign currency exchange rates by entering into derivative financial instruments, principally foreign currency forward purchase and sale contracts. The following table summarizes the notional amounts, average settlement rates, and fair value for foreign currency forward purchase and sale contracts as of December 31, 2001:

		Notional Amount in Foreign Currency (in millions)	Average Settlement Rates	Fair Value in U.S. Dollars (in millions)
Canadian Dollars	Purchase	401	.653	$(18)
	Sell	291	.680	17
Euros	Purchase	550	.928	(33)
				$(34)

The following table summarizes foreign currency forward purchase and sale contracts by expected maturity dates along with annual anticipated cash flow impacts as of December 31, 2001:

		Expected Maturity Dates						
		2002	2003	2004	2005	2006	Thereafter	Total
		(in millions)						
Canadian Dollars	Purchase	$(11)	$(6)	$(2)	$—	$ —	$ 1	$(18)
	Sell	10	5	2	—	—	—	17
Euros	Purchase	—	—	—	—	(33)	—	(33)
	Net cash flow effect	$ (1)	$(1)	$—	$—	$(33)	$ 1	$(34)

Equity Risk

Our Merchant Energy segment holds investments that expose us to price risk associated with equity securities markets. We account for these investments using investment company accounting. As a result, these holdings are measured at their fair value with changes in fair value recorded in our income statement. The fair value of these investments are determined based on estimates of amounts that would be realized if these securities were sold. We also hold a variety of publicly traded marketable equity securities. Below are the fair values of these holdings at December 31, 2001 and 2000, as well as the impact of a ten percent increase or decrease in the underlying fair values of these securities for each period presented:

	2001			2000		
	Fair Value	Impact of 10 Percent Increase	Impact of 10 Percent Decrease	Fair Value	Impact of 10 Percent Increase	Impact of 10 Percent Decrease
	(in millions)					
Investment funds	$13	$ 1	$(1)	$ 7	$ 1	$(1)
Securities	15	2	(2)	54	5	(5)
Other	—	—	—	1	—	—
Total	$28	$ 3	$(3)	$62	$ 6	$(6)

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)

	Year Ended December 31,		
	2001	2000	1999
Operating revenues	$57,475	$48,915	$27,325
Operating expenses			
Cost of natural gas and other products	50,043	42,430	22,163
Operation and maintenance	2,906	2,446	2,197
Merger-related costs and asset impairments	1,843	125	557
Ceiling test charges	135	—	352
Depreciation, depletion and amortization	1,359	1,247	1,101
Taxes, other than income taxes	356	283	245
	56,642	46,531	26,615
Operating income	833	2,384	710
Other income			
Earnings from unconsolidated affiliates	496	392	285
Other, net	292	242	224
	788	634	509
Income before interest, income taxes and other charges	1,621	3,018	1,219
Interest and debt expense	1,155	1,040	776
Minority interest	217	204	93
Income taxes	182	538	93
	1,554	1,782	962
Income before extraordinary items and cumulative effect of accounting change	67	1,236	257
Extraordinary items, net of income taxes	26	70	—
Cumulative effect of accounting change, net of income taxes	—	—	(13)
Net income	$ 93	$ 1,306	$ 244
Basic earnings per common share			
Income before extraordinary items and cumulative effect of accounting change	$ 0.13	$ 2.50	$ 0.52
Extraordinary items, net of income taxes	0.05	0.14	—
Cumulative effect of accounting change, net of income taxes	—	—	(0.03)
Net income	$ 0.18	$ 2.64	$ 0.49
Diluted earnings per common share			
Income before extraordinary items and cumulative effect of accounting change	$ 0.13	$ 2.43	$ 0.52
Extraordinary items, net of income taxes	0.05	0.14	—
Cumulative effect of accounting change, net of income taxes	—	—	(0.03)
Net income	$ 0.18	$ 2.57	$ 0.49
Basic average common shares outstanding	505	494	490
Diluted average common shares outstanding	516	513	497

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2001	December 31, 2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,139	$ 741
Accounts and notes receivable, net of allowance of $274 in 2001 and $128 in 2000		
Customer	5,074	6,188
Unconsolidated affiliates	911	392
Other	896	776
Inventory	825	1,335
Assets from price risk management activities	2,702	4,860
Other	1,112	832
Total current assets	12,659	15,124
Property, plant and equipment, at cost		
Pipelines	17,596	16,682
Refining, crude oil and chemical facilities	2,425	2,606
Power facilities	834	383
Natural gas and oil properties, at full cost	14,466	11,032
Gathering and processing systems	2,628	2,884
Other	1,021	929
	38,970	34,516
Less accumulated depreciation, depletion and amortization	14,379	12,254
Total property, plant and equipment, net	24,591	22,262
Other assets		
Investments in unconsolidated affiliates	5,297	4,410
Assets from price risk management activities	2,118	1,777
Other	3,506	2,747
	10,921	8,934
Total assets	$48,171	$46,320

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS — (Continued)
(In millions, except share amounts)

	December 31, 2001	December 31, 2000
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 4,971	$ 5,143
Unconsolidated affiliates	26	14
Other	959	1,742
Short-term borrowings and other financing obligations	3,314	3,629
Notes payable to unconsolidated affiliates	504	396
Liabilities from price risk management activities	1,868	3,427
Other	1,923	1,324
Total current liabilities	13,565	15,675
Debt		
Long-term debt and other financing obligations	12,816	11,603
Notes payable to unconsolidated affiliates	368	343
	13,184	11,946
Other		
Liabilities from price risk management activities	1,231	1,010
Deferred income taxes	4,459	4,106
Other	2,363	1,757
	8,053	6,873
Commitments and contingencies		
Securities of subsidiaries		
Company-obligated preferred securities of consolidated trusts	925	925
Minority interests	3,088	2,782
	4,013	3,707
Stockholders' equity		
Common stock, par value $3 per share; authorized 750,000,000 shares; issued 538,363,664 shares in 2001 and 513,815,775 shares in 2000	1,615	1,541
Additional paid-in capital	3,130	1,925
Retained earnings	4,902	5,243
Accumulated other comprehensive income	157	(65)
Treasury stock (at cost); 7,628,799 shares in 2001 and 13,943,779 shares in 2000	(261)	(400)
Unamortized compensation	(187)	(125)
Total stockholders' equity	9,356	8,119
Total liabilities and stockholders' equity	$48,171	$46,320

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2001	2000	1999
Cash flows from operating activities			
Net income	$ 93	$ 1,306	$ 244
Adjustments to reconcile net income to net cash from operating activities			
Depreciation, depletion and amortization	1,359	1,247	1,101
Ceiling test charges	135	—	352
Deferred income tax expense	192	531	68
Net gain on the sale of assets	(25)	(50)	(27)
Extraordinary items	(53)	(120)	—
Undistributed earnings of unconsolidated affiliates	(198)	(71)	(91)
Non-cash portion of merger-related costs, asset impairments and changes in estimates	1,618	11	380
Non-cash portion of price risk management activities	(852)	(443)	(281)
Other	54	(19)	(8)
Working capital changes, net of non-cash transactions			
Accounts and notes receivable	1,032	(3,040)	(1,080)
Inventory	447	(147)	(265)
Change in trading price risk management activities, net	1,456	(1,373)	77
Accounts payable	(968)	2,148	710
Other working capital changes	26	198	91
Non-working capital changes and other	(196)	(79)	(4)
Net cash provided by operating activities	4,120	99	1,267
Cash flows from investing activities			
Additions to property, plant and equipment	(4,079)	(3,448)	(2,867)
Additions to investments	(2,639)	(1,673)	(1,473)
Cash paid for acquisitions, net of cash acquired	(299)	(524)	(165)
Net proceeds from the sale of assets	548	787	70
Proceeds from the sale of investments	354	354	122
Repayment of notes receivable from unconsolidated affiliates	1,077	647	—
Other	16	23	(104)
Net cash used in investing activities	(5,022)	(3,834)	(4,417)
Cash flows from financing activities			
Net repayments of commercial paper and short-term credit facilities	(328)	(64)	(125)
Borrowings under credit facilities	245	455	—
Repayments on credit facilities	(700)	—	—
Net proceeds from the issuance of notes payable	—	58	101
Repayments of notes payable	(3)	(82)	—
Net proceeds from the issuance of long-term debt and other financing obligations	3,260	2,619	3,126
Payments to retire long-term debt and other financing obligations	(1,892)	(865)	(830)
Net proceeds from issuance of preferred securities	—	293	—
Issuances of common stock	915	141	39
Dividends paid	(387)	(243)	(238)
Increase in notes payable to unconsolidated affiliates	521	1,207	121
Decrease in notes payable to unconsolidated affiliates	(612)	(600)	—
Net proceeds from issuance of minority interests in subsidiaries	281	995	1,310
Net cash provided by financing activities	1,300	3,914	3,504
Increase in cash and cash equivalents	398	179	354
Cash and cash equivalents			
Beginning of period	741	562	208
End of period	$ 1,139	$ 741	$ 562

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions)

	For the Years Ended December 31,					
	2001		2000		1999	
	Shares	Amount	Shares	Amount	Shares	Amount
Common stock, $3.00 par:						
Balance at beginning of year	514	$ 1,541	507	$1,520	503	$1,508
Compensation related issuances	3	10	6	18	4	13
Equity offering	20	61	—	—	—	—
Conversion of Coastal options	4	13	—	—	—	—
Other	(3)	(10)	1	3	—	(1)
Balance at end of year	538	1,615	514	1,541	507	1,520
Additional paid-in capital:						
Balance at beginning of year		1,925		1,667		1,575
Compensation related issuances		188		171		96
Tax benefit of equity plans		31		60		19
Equity offering		802		—		—
Retirement of Coastal treasury shares		(132)				
Conversion of Coastal options		265		—		—
Other		51		27		(23)
Balance at end of year		3,130		1,925		1,667
Retained earnings:						
Balance at beginning of year		5,243		4,180		4,197
Net income		93		1,306		244
Dividends ($0.850, $0.824, and $0.800 per share)		(434)		(243)		(261)
Balance at end of year		4,902		5,243		4,180
Accumulated other comprehensive income:						
Balance at beginning of year		(65)		(37)		(20)
Other comprehensive income		222		(28)		(17)
Balance at end of year		157		(65)		(37)
Treasury stock, at cost:						
Balance at beginning of year	(14)	(400)	(14)	(405)	(10)	(282)
Compensation related issuances	1	11	—	3	(5)	(182)
Retirement of Coastal treasury shares	5	132	—	—	—	—
Retirement of Sonat treasury shares	—	—	—	2	1	59
Other	—	(4)	—	—	—	—
Balance at end of year	(8)	(261)	(14)	(400)	(14)	(405)
Unamortized compensation:						
Balance at beginning of year		(125)		(41)		(65)
Issuance of new restricted stock		(121)		(97)		(50)
Amortization of restricted stock		67		13		6
Other		(8)		—		1
Early vesting of equity plans		—		—		67
Balance at end of year		(187)		(125)		(41)
Total stockholders' equity	530	$ 9,356	500	$8,119	493	$6,884

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (In millions)

	Year Ended December 31,		
	2001	2000	1999
Comprehensive Income			
Net income	$ 93	$1,306	$244
Foreign currency translation adjustments	(33)	(30)	(12)
Unrealized net gains (losses) from cash flow hedging activities:			
Cumulative-effect of transition adjustment (net of tax of $673)	(1,280)	—	—
Reclassification of initial cumulative-effect of transition adjustment at original value (net of tax of $568)	1,063	—	—
Additional reclassification adjustments for changes in initial value to settlement date (net of tax of $285)	(569)	—	—
Unrealized mark-to-market gains arising during period (net of tax of $548)	1,042	—	—
Other	(1)	2	(5)
Other comprehensive income	222	(28)	(17)
Comprehensive income	$ 315	$1,278	$227
Accumulated Other Comprehensive Income			
Beginning balances as of December 31, 2000, 1999 and 1998	$ (65)	$ (37)	$(20)
Foreign currency translation adjustments	(33)	(30)	(12)
Unrealized net gains (losses) from cash flow hedging activities:			
Cumulative-effect of transition adjustment, net of taxes	(1,280)	—	—
Reclassification of initial cumulative effect of transition adjustment at original value, net of taxes	1,063	—	—
Additional reclassification adjustments for changes in initial value to settlement date, net of taxes	(569)	—	—
Unrealized mark-to-market gains arising during period, net of taxes	1,042	—	—
Other	(1)	2	(5)
Balance as of December 31,	$ 157	$ (65)	$(37)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications had no impact on reported net income or stockholders' equity.

Principles of Consolidation

We consolidate entities when we have the ability to control the operating and financial decisions and policies of that entity. Where we can exert significant influence over, but do not control, those policies and decisions, we apply the equity method of accounting. We use the cost method of accounting where we are unable to exert significant influence over the entity. The determination of our ability to control or exert significant influence over an entity involves the use of judgment of the extent of our control or influence and that of the other equity owners or participants of the entity.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues, and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates. Our accounting policies for asset impairments, natural gas and oil properties, environmental costs and other contingencies, and price risk management activities require estimates that involve complex situations and a high degree of judgment. These estimates can, and often do, change.

Accounting for Regulated Operations

Our interstate natural gas systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Our regulated interstate systems apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, except for ANR, CIG and WIC, who discontinued its application in 1996. Accounting for businesses that are regulated and apply the provisions of SFAS No. 71 can differ from the accounting requirements for non-regulated businesses. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, employee related benefits, and other costs and taxes included in, or expected to be included in, future rates.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

Inventory

Our inventory consists of refined products, crude oil and chemicals, materials and supplies, natural gas in storage for non-trading purposes, coal and optic fiber. We use the first-in, first-out method to account for our refined products, crude oil and chemicals inventories and the average cost method to account for our other inventories. We value all inventory at the lower of its cost or market value. Our optic fiber has been classified as a long-term asset since we do not expect to sell it in the next twelve months.

Natural Gas and Oil Imbalances

Natural gas and oil imbalances occur when the actual amount of natural gas or oil delivered from or received by a pipeline system, processing plant or storage facility differs from the contractual amount scheduled to be delivered or received. We value these imbalances due to or from shippers and operators at an appropriate market index price based on when we expect to settle the imbalance. Imbalances are settled in cash or made up in-kind, subject to the contractual terms of settlement.

Imbalances due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from unconsolidated affiliates. Imbalances owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to unconsolidated affiliates. In addition, all imbalances are classified as current or long-term depending on when we expect to settle them.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or, the cost to the entity that first placed the asset in service. We capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We capitalize the major units of property replacements or improvements and expense minor items. Included in our pipeline property balances are additional acquisition costs which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems. These costs are amortized on a straight-line basis, and we do not recover these excess costs in our rates.

The following table presents our property, plant and equipment by type, depreciation method, remaining useful lives and depreciation rate:

Type	Method	Remaining Useful Lives	Rates
		(In years)	
Regulated interstate systems			
SFAS No. 71[(1)]	Composite	2-35	1% to 33%
Non-SFAS No. 71	Straight-line	2-53	2% to 27%
Non-regulated systems			
Transmission and storage facilities	Straight-line	19-61	2% to 5%
Refining, crude oil and chemical facilities	Straight-line	1-33	3% to 20%
Power facilities	Straight-line	1-49	2% to 33%
Gathering and processing systems	Straight-line	1-40	3% to 40%
Coal facilities	Straight-line	1-30	3% to 33%
Transportation equipment	Straight-line	1-5	10% to 33%
Buildings and improvements	Straight-line	1-43	2% to 20%
Office and miscellaneous equipment	Straight-line	1-10	5% to 50%

(1) For our regulated interstate systems using SFAS No. 71, we use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar useful lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff, to the total cost of the group, until its net book value equals its salvage value. We re-evaluate depreciation rates each time we redevelop our transportation rates when we file with FERC for an increase or decrease in rates.

When we retire regulated property, plant and equipment accounted for under SFAS No. 71, we charge accumulated depreciation and amortization for the original cost, plus the cost of retirement (the cost to remove, sell or dispose), less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in income. When we retire regulated property, plant and equipment not under SFAS No. 71 and non-regulated properties, we reduce property, plant and equipment for its original cost, less accumulated depreciation, and salvage. Any remaining gain or loss is recorded in income.

Asset Impairments

We evaluate our long-lived assets for impairment in accordance with SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.* If an adverse event or change in circumstances occurs, we estimate the future cash flows from the asset, grouped together at the lowest level for which separate cash flows can be measured, to determine if the asset is impaired. If the total of the undiscounted future cash flows is less than the carrying amount for the assets, we calculate the fair value of the assets either through reference to sales data for similar assets, or by estimating the fair value using a discounted cash flow approach. These cash flow estimates require us to make estimates and assumptions for many years into the future for pricing, demand, competition, operating costs, legal, regulatory and other factors, and these assumptions can change either positively or negatively.

Natural Gas and Oil Properties

We use the full cost method to account for our natural gas and oil properties. Under the full cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized. These capitalized costs include the costs of all unproved properties, internal costs directly related to acquisition and exploration activities and capitalized interest.

We amortize these costs using the unit of production method over the life of our proved reserves. Our total capitalized costs are limited to a ceiling based on the present value of future net revenues using current prices, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. If these discounted revenues are not equal to or greater than total capitalized costs, we are required to write-down our capitalized costs to this level. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statements as ceiling test charges. Our ceiling test calculations include the effects of derivative instruments we have designated as cash flow hedges of our anticipated future natural gas and oil production.

We do not recognize a gain or loss on sales of our natural gas and oil properties, unless the properties sold are significant. We treat sales as an adjustment to the cost of our properties.

Planned Major Maintenance

Repair and maintenance costs are generally expensed as incurred, unless they improve the operating efficiency or extend the useful life of an asset.

In our domestic refining business, repair and maintenance costs for planned major maintenance activities are accrued as a liability in a systematic and rational manner over the period of time until the planned major maintenance activities occur. Any difference between the accrued liability and the actual costs incurred in performing the maintenance activities are charged or credited to expense at the time the maintenance occurs. At our international refineries, the cost of each major maintenance activity is capitalized and amortized to expense in a systematic and rational manner over the estimated period extending to the next planned major maintenance activity. The types of costs we accrue in conjunction with major maintenance at our refineries are outside contractor costs, materials and supplies, company labor and other outside services. For our domestic operations, we had accruals for major maintenance of $36 million and $51 million at December 31, 2001 and 2000, and for our international operations, we capitalized $56 million and $53 million at December 31, 2001 and 2000.

Intangible Assets

Intangible assets consist primarily of goodwill arising as a result of mergers and acquisitions. We amortize these intangible assets using the straight-line method over periods ranging from 5 to 40 years. We evaluate impairment of goodwill in accordance with APB No. 17, *Intangible Assets*. Under this methodology, when an event occurs that suggests that an impairment may have occurred, we evaluate the undiscounted net cash flows of the asset or entity to which the goodwill relates. If these cash flows are not sufficient to recover the value of the asset or entity plus its related goodwill, these cash flows are discounted at a risk-adjusted rate with any difference recorded as a charge in our income statement.

Revenue Recognition

Our regulated businesses recognize revenues from natural gas transportation services and services other than transportation in the period when the service is provided. Reserves are provided on revenues collected that may be subject to refund in our pending rate proceedings.

Our non-regulated businesses record revenues when they are earned. Revenues are earned when deliveries of physical commodities are made, or when services are provided. See the discussion of price risk management activities below for our revenue recognition policies on our trading activities.

Environmental Costs and Other Contingencies

We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods by preventing or eliminating future contamination. We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the EPA or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage, government sponsored and other programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Price Risk Management Activities

We engage in price risk management activities for both trading and for non-trading purposes to manage market risks associated with commodities we purchase and sell, interest rates and foreign currency exchange rates.

Our trading and non-trading price risk management activities involve the use of a variety of derivative financial instruments, including:

- exchange-traded futures contracts that involve cash settlements;
- forward contracts that involve cash settlements or physical delivery of a commodity;
- swap contracts that require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity; and
- exchange-traded and over-the-counter options.

Trading Activities. Our trading activities include the services we provide in the energy sector, primarily related to the purchase and sale of energy commodities. We account for our trading activities at their fair market value under the requirements of EITF Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* In addition to the derivatives above, our trading activities also include non-derivative instruments such as transportation and storage capacity contracts, and physical natural gas that is actively traded. We reflect the market values of our trading activities in our balance sheet as price risk management activities. These are classified as current or long-term based on their anticipated settlement date. In our income statement, we account for physical settlements that result in delivery of a commodity as revenues or cost of products sold based on whether we buy or sell the commodity. Financial settlements as well as changes in the market value of traded positions are included in revenue.

Non-trading Activities. Our non-trading price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures on our assets, liabilities, contractual commitments and forecasted transactions related to our natural gas and oil production, refining, natural gas transmission, power generation, financing and international business activities. On January 1, 2001, we adopted the provisions of SFAS No. 133, *Accounting for Derivatives and Hedging Activities*, in accounting for our non-trading derivative instruments. Under SFAS No. 133, all derivatives are reflected in our balance sheet at their fair market value. We do not apply the mark-to-market method of accounting for contracts that qualify as normal purchases and sales under SFAS No. 133.

We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Hedges of fair value exposure are entered into to hedge the fair value of a recognized asset, liability or a firm commitment. On the date that we enter into the derivative contract, we designate the derivative as either a cash flow hedge or a fair value hedge. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings as a component of operating revenues in our income statement. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of related hedged assets, liabilities or firm commitments.

As required by SFAS No. 133, we formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is no longer highly effective as a hedge.

The market value of both trading and non-trading instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity. Our estimates also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. Our actual results may differ from our estimates, and these differences can be positive or negative.

Cash inflows and outflows associated with the settlement of both trading and non-trading price risk management activities are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported separately from price risk management activities in our balance sheet as trade receivables and payables.

Prior to our adoption of SFAS No. 133, we applied hedge accounting for our non-trading derivatives only if the derivative reduced the risk of the underlying hedged item, was designated as a hedge at its inception and was expected to result in financial impacts which were inversely correlated to those of the item being hedged. If correlation ceased to exist, hedge accounting was terminated and the derivatives were recorded at their fair value in the balance sheet and changes in fair value were recorded in income. Changes in the market value of derivatives designated as hedges were deferred as deferred revenue or expense until the gain or loss was recognized on the hedged transaction. Derivatives held for non-trading purposes were recorded as gains or losses in operating income and cash inflows and outflows were recognized in operating cash flow as the settlement of those transactions occurred.

Income Taxes

We report income taxes based on income reported on our tax returns along with a provision for deferred income taxes. Deferred income taxes reflect the estimated future tax consequences of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

Foreign Currency Transactions and Translation

We record all currency transaction gains and losses in income. The net currency loss recorded to income in 2001 was $13 million and was insignificant in 2000. The U.S. dollar is the functional currency for substantially all of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and included as a separate component of comprehensive income and stockholders' equity. The cumulative currency translation loss recorded in accumulated other comprehensive income was $97 million and $64 million at December 31, 2001 and 2000. Revenues and expenses are translated at average exchange rates prevailing during the year.

Treasury Stock

We account for treasury stock using the cost method and report it in our balance sheet as a reduction to stockholders' equity. Treasury stock sold or issued is valued on a first-in, first-out basis. Included in treasury stock at December 31, 2001, and 2000, were approximately 5.5 million shares and 5.8 million shares of common stock held in a trust under our deferred compensation programs.

Stock-Based Compensation

We apply the provisions of Accounting Principles Board Opinion No. 25 and its related interpretations in accounting for our stock compensation plans. We have both fixed and variable compensation plans, and we account for these plans using fixed and variable accounting as appropriate. Compensation expense for variable plans, including restricted stock grants, is measured using the market price of the stock on the date the number of shares in the grant becomes determinable and is amortized into earnings over the period of service. Our stock options are issued under a fixed plan. Accordingly, compensation expense is not recognized for stock options unless the options were granted at an exercise price lower than market on the grant date.

Earnings Per Share

Basic earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period. Diluted earnings per share represents the amount of earnings for the period available to each share of common stock outstanding during the period plus all potentially dilutive common shares outstanding during the period. Differences between basic and diluted shares outstanding in all periods are attributed to the dilutive effects of restricted stock, stock options, trust preferred securities, convertible debentures and our FELINE PRIDES[sm].

Cumulative Effect of Accounting Change

On January 1, 1999, we adopted Statement of Position 98-5, *Reporting on the Costs of Start-Up Activities.* The statement defined start-up activities and required start-up and organization costs be expensed as incurred. In addition, it required that any such cost that existed on the balance sheet be expensed upon adoption of the pronouncement. We recorded a charge of $13 million, net of income taxes, as a cumulative effect of an accounting change upon adoption.

New Accounting Pronouncements Issued But Not Yet Adopted

During 2001, the Financial Accounting Standards Board issued SFAS No. 141, *Business Combinations,* SFAS No. 142 *Goodwill and Other Intangible Assets* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* Each of these standards has a required adoption date of January 1, 2002. SFAS No. 141 will impact the manner in which we account for business combinations. SFAS No. 142 will impact the manner in which we account for goodwill and test goodwill for impairment. SFAS No. 144 will impact how we account for asset impairments and the accounting for discontinued operations.

2. Mergers, Acquisitions and Divestitures

Coastal

In January 2001, we merged with Coastal. We accounted for the transaction as a pooling of interests and converted each share of Coastal's common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We also exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. In the merger, we issued approximately 271 million shares of our common stock, including 4 million shares in exchange for Coastal stock options.

The following table presents the revenues and net income for the previously separate companies and the combined amounts presented in these audited combined financial statements. Several adjustments were made to conform the accounting presentation of this financial information.

	Year ended December 31,	
	2000	1999
	(In millions)	
Revenues		
El Paso	$21,950	$10,709
Coastal	18,014	10,331
Conforming reclassifications[1]	8,951	6,285
Combined	$48,915	$27,325
Extraordinary items, net of income taxes		
El Paso	$ 70	$ —
Coastal	—	—
Combined	$ 70	$ —
Net income (loss)		
El Paso	$ 652	$ (255)
Coastal	654	499
Combined	$ 1,306	$ 244

[1] Conforming reclassifications primarily include a gross-up of revenues associated with Coastal's physical petroleum marketing and trading activities to be consistent with our method of reporting these revenues.

Texas Midstream Operations

In December 2000, we completed our purchase of Pacific Gas & Electric's (PG&E's) Texas Midstream operations. The total value of the transaction was $887 million, including assumed debt of approximately $527 million. The transaction was accounted for as a purchase and is included in our Field Services segment.

The operations acquired consisted of 7,500 miles of intrastate natural gas transmission and natural gas liquids pipelines that transport approximately 2.8 Bcf/d, nine natural gas processing and fractionation plants that currently process 1.5 Bcf/d and rights to 7.2 Bcf of natural gas storage capacity. In March 2001, we sold some of these acquired natural gas liquids transportation and fractionation assets to El Paso Energy Partners for approximately $133 million.

Sonat

In October 1999, we completed our merger with Sonat, a diversified energy holding company engaged in domestic natural gas and oil exploration and production, the transmission and storage of natural gas, and natural gas and power marketing. We accounted for the merger as a pooling of interests and exchanged one share of our common stock was issued in exchange for each share of Sonat common stock. Total common shares issued in the merger were approximately 110 million.

Divestitures

Under a Federal Trade Commission (FTC) order, as a result of our merger with Coastal, we sold our Midwestern Gas Transmission system, our Gulfstream pipeline project, our 50 percent interest in the Stingray and U-T Offshore pipeline systems and our investments in the Empire State and Iroquois pipeline systems. For the year ended December 31, 2001, net proceeds from these sales were approximately $279 million, and we recognized an extraordinary net gain of approximately $26 million, net of income taxes of approximately $27 million.

Additionally, El Paso Energy Partners, L.P. sold its interests in several offshore assets under an FTC order related to our merger with Coastal. These sales consisted of interests in seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Proceeds from the sales of these assets were approximately $135 million and resulted in a loss to the partnership of approximately $25 million. As consideration for these sales, we committed to pay El Paso Energy Partners a series of payments totaling $29 million, and were required to contribute $40 million to a trust related to one of the assets sold by El Paso Energy Partners. These payments have been recorded as merger-related costs.

During 2000, we sold East Tennessee Natural Gas Company, Sea Robin Pipeline Company and our one-third interest in Destin Pipeline Company to comply with an FTC order related to our merger with Sonat. Net proceeds from these sales were approximately $616 million, and we recognized an extraordinary gain of $89 million, net of income taxes of $59 million. In December 2000, we sold our interest in Oasis Pipeline Company to comply with an FTC order. We incurred a loss on this transaction of approximately $19 million, net of income taxes. We recorded the gains and losses on these sales as extraordinary items in our income statement.

In February 2002, we announced the sale of several midstream assets to El Paso Energy Partners for total consideration of $750 million. The assets to be sold include:

- 9,400 miles of intrastate transmission pipelines;
- 1,300 miles of gathering systems in the Permian Basin; and
- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

3. Merger-Related Costs and Asset Impairments

We incurred costs related to our mergers with Coastal and Sonat and asset impairments for each of the three years ended December 31 as follows:

	2001	2000	1999
		(In millions)	
Merger-related costs	$1,684	$ 93	$515
Asset impairments	159	32	42
	$1,843	$125	$557

Merger-Related Costs. Our merger-related costs relate to our mergers with Coastal and Sonat and consisted of the following for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
Employee severance, retention and transition costs	$ 840	$31	$303
Transaction costs	70	60	62
Business and operational integration costs	382	—	31
Merger-related asset impairments	163	—	78
Other	229	2	41
	$1,684	$93	$515

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following the Coastal merger, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. Following the Sonat merger, approximately 870 full-time positions were eliminated in a similar restructuring. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of these restructurings. Retention charges include payments to employees who were retained following the mergers and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. The pension and post-retirement benefits were accrued on the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid.

Also included in the 2001 employee severance, retention and transition costs was a charge of $278 million resulting from the issuance of approximately 4 million shares of our common stock on the date of the Coastal merger in exchange for the fair value of Coastal employees' and directors' stock options.

Transaction costs include investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete our mergers. All of these items were expensed in the periods in which they were incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments, such as lease termination and abandonment charges, recognition of the mark-to-market value of energy trading contracts resulting from changes in how these contracts are managed under our combined operating strategy and incremental fees under software and seismic license agreements. Also included in the 2001 charges are approximately $222 million in estimated lease related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas and from El Paso, Texas to Colorado Springs, Colorado. These charges were accrued at the time we completed our relocations and closed these offices. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed as incurred.

Merger-related asset impairments relate to write-offs or write-downs of capitalized costs for duplicate systems and facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following our merger with Coastal. These charges occurred in our Merchant Energy, Production and Pipelines segments, and all of these assets have either had their operations suspended or continue to be held for use. The charges taken were based on a comparison of the cost of the assets to their estimated fair value to the ongoing operations based on this change in operating strategy.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of our merger with Coastal and other miscellaneous charges. These items were expensed in the period in which they were incurred.

Asset Impairments. The 2001 asset impairment charges resulted from the write-downs of our investments in several international power projects in our Merchant Energy segment and several telecommunications investments in our Corporate and Other operations. The 2000 charges consisted of the impairment of coal mining and refining assets in our Merchant Energy segment and a gas processing facility in our Field Services segment. The 1999 charge occurred in the Pipeline segment and was derived from impairments of regulatory assets that were not recoverable based on the settlement of a rate case. The impairments in all periods were primarily a result of weak or changing economic conditions causing permanent declines in the value of these assets, and the charges taken for all assets were based on a comparison of each asset's carrying value to its estimated fair value based on future estimated cash flows. These assets continue to be held for use, or their operations have been suspended.

4. Changes in Accounting Estimates

Included in our operation and maintenance costs for the year ended December 31, 2001, were approximately $317 million in costs related to changes in accounting estimates which consist of $232 million in additional environmental remediation liabilities, $47 million of additional accrued legal obligations and a $38 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. These changes were primarily the result of several events that occurred as part of and following our merger with Coastal, including the consolidation of numerous operating locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These changes were also a direct result of a fire at our Aruba refinery. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. These charges are included as operating expenses in our income statement and reduced our net income before extraordinary items and net income for the year ended December 31, 2001, by approximately $215 million.

5. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. During the third quarter of 2001, capitalized costs exceeded this ceiling limit by $135 million, including $87 million for our Canadian full cost pool, $28 million for our Brazilian full cost pool and $20 million for other international production operations, primarily in Turkey. These charges were based on the November 1, 2001 daily posted oil and natural gas sales prices. During 1999, we incurred charges related to our U.S. full cost pool of $352 million based on end of period natural gas and oil prices. The natural gas and oil prices used in both periods were adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. These non-cash write-downs are included in our income statement as ceiling test charges.

We use financial instruments to hedge against volatility of natural gas and oil prices. The impact of these hedges was considered in the determination of our ceiling test charge during 2001, and will be factored into future ceiling test calculations. Had the impact of our hedges not been included in calculating our 2001 ceiling test charge, the charge would not have materially changed since we do not significantly hedge our international production activities.

Also as mentioned above, our 2001 charge was computed based on daily posted prices on November 1, 2001. Had we computed this charge based on the daily oil and natural gas prices as of September 30, 2001, the charge would have been approximately $275 million, including approximately $227 million for our Canadian full cost pool and $48 million for our Brazilian and other international production operations, including the impact on future cash flows of our hedging program. Had the impact of our hedging program been excluded, the charges would have been approximately the same for our international full costs pools and production operations, but we would have incurred an additional charge of approximately $576 million related to our U.S. full cost pool.

6. Income Taxes

Pretax income before extraordinary items and cumulative effect of accounting change are composed of the following for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
United States	$171	$1,525	$175
Foreign	78	249	175
	$249	$1,774	$350

The following table reflects the components of income tax expense included in income before extraordinary items and cumulative effect of accounting change for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
Current			
Federal	$(41)	$(78)	$ 1
State	(28)	(20)	5
Foreign	30	16	19
	(39)	(82)	25
Deferred			
Federal	278	566	61
State	(4)	54	5
Foreign	(53)	—	2
	221	620	68
Total income tax expense	$182	$538	$93

Our tax expense, included in income before extraordinary items and cumulative effect of accounting change, differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
Tax expense at the statutory federal rate of 35%	$ 87	$621	$123
Increase (decrease)			
State income tax, net of federal income tax benefit	(21)	22	7
Dividend exclusion	(20)	(28)	(17)
Non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities	115	12	29
Foreign income taxed at different rates	14	(60)	(22)
Deferred credit on loss carryover	(7)	(18)	—
Preferred stock dividends of a subsidiary	12	13	9
Non-conventional fuel tax credit	(6)	(9)	(6)
Depreciation, depletion and amortization	23	(14)	(7)
Other	(15)	(1)	(23)
Income tax expense	$182	$538	$ 93
Effective tax rate	73%	30%	27%

The following are the components of our net deferred tax liability at as of December 31:

	2001	2000
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$4,319	$4,300
Investments in unconsolidated affiliates	706	458
Price risk management activities	564	244
Regulatory and other assets	1,146	707
Total deferred tax liability	6,735	5,709
Deferred tax assets		
U.S. net operating loss and tax credit carryovers	1,051	699
Environmental liability	220	94
Other liabilities	1,167	875
Valuation allowance	(3)	(3)
Total deferred tax asset	2,435	1,665
Net deferred tax liability	$4,300	$4,044

At December 31, 2001, the portion of the cumulative undistributed earnings of our foreign subsidiaries and foreign corporate joint ventures on which we have not recorded U.S. income taxes was approximately $975 million. Since these earnings have been or are intended to be indefinitely reinvested in foreign operations, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustment recorded in other comprehensive income.

The tax benefit associated with the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends, reduced taxes payable by $31 million in 2001, $60 million in 2000 and $19 million in 1999. These benefits are included in additional paid-in capital in our balance sheets.

As of December 31, 2001, we have charitable contribution carryovers of $24 million for which the carryover periods end as follows: $1 million in 2002, $1 million in 2003 and $22 million in 2004; alternative minimum tax credits of $225 million that carryover indefinitely; and $2 million of general business credit carryovers for which the carryover periods end at various times in the years 2006 through 2020. Usage of these carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations. The table below presents the details of our net operating loss carryover periods.

	Carryover Period				
	2002	2003 - 2010	2011 - 2015	2016 - 2021	Total
			(In millions)		
Net operating loss	—	$ 74	$ 256	$ 1,998	$ 2,328

We recorded a valuation allowance to reflect the estimated amount of deferred tax assets which we may not realize due to the expiration of net operating loss and tax credit carryovers. As of December 31, 2001 and 2000, approximately $1 million of the valuation allowance relates to net operating loss carryovers of an acquired company. The remaining $2 million of the allowance relates to general business credit carryovers.

7. Earnings Per Share

We calculated basic and diluted earnings per share amounts as follows for each of the three years ended December 31:

	2001		2000		1999	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)					
Income from continuing operations	$ 67	$ 67	$1,236	$1,236	$ 257	$ 257
Preferred stock dividend	—	—	—	—	—	—
Income from continuing operations available to common stockholders	67	67	1,236	1,236	257	257
Trust preferred securities(1)	—	—	—	10	—	—
Convertible debentures(1)	—	—	—	—	—	—
Adjusted income from continuing operations	67	67	1,236	1,246	257	257
Extraordinary items, net of income taxes	26	26	70	70	—	—
Cumulative effect of accounting change, net of income taxes	—	—	—	—	(13)	(13)
Adjusted net income	$ 93	$ 93	$1,306	$1,316	$ 244	$ 244
Average common shares outstanding	505	505	494	494	490	490
Effect of diluted securities						
Restricted stock	—	1	—	—	—	—
Stock options	—	5	—	7	—	5
FELINE PRIDES[sm]	—	5	—	3	—	—
Preferred stock	—	—	—	1	—	2
Trust preferred securities(1)	—	—	—	8	—	—
Convertible debentures(1)	—	—	—	—	—	—
Average common shares outstanding	505	516	494	513	490	497
Earnings per common share						
Adjusted income from continuing operations	$0.13	$0.13	$ 2.50	$ 2.43	$ 0.52	$ 0.52
Extraordinary items, net of income taxes	0.05	0.05	0.14	0.14	—	—
Cumulative effect of accounting change, net of income taxes	—	—	—	—	(0.03)	(0.03)
Adjusted net income	$0.18	$0.18	$ 2.64	$ 2.57	$ 0.49	$ 0.49

(1) Due to its antidilutive effect on earnings per share, approximately 7 million shares related to our convertible debentures were excluded from 2001 diluted shares, and approximately 8 million shares related to our trust preferred securities were excluded in 2001 and 1999.

8. Financial Instruments and Price Risk Management Activities

Fair Value of Financial Instruments

Following are the carrying amounts and estimated fair values of our financial instruments as of December 31:

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Balance sheet financial instruments:				
Investments	$ 28	$ 28	$ 62	$ 62
Long-term debt and other obligations, including current maturities	14,615	14,089	12,931	13,123
Notes payable to unconsolidated affiliates	872	896	739	762
Company obligated preferred securities of subsidiaries	925	1,048	925	1,172
Trading instruments				
Futures contracts	(206)	(206)	149	149
Option contracts[1]	553	553	(118)	(118)
Swap and forward contracts[1]	(107)	(107)	1,379	1,379
Other financial instruments:				
Non-Trading instruments[2]				
Commodity futures contracts	$ 25	$ 25	$ —	$ 42
Commodity option contracts	(17)	(17)	—	—
Commodity swap and forward contracts	427	427	—	(1,907)
Foreign currency swaps and forward purchases	(33)	(33)	—	—

(1) Excludes all physical contracts including transportation capacity, tolling agreements and natural gas in storage held for trading purposes since these do not constitute financial instruments.

(2) On January 1, 2001, we adopted SFAS No. 133. Under SFAS No. 133, all derivative instruments are recorded at their fair value in our financial statements.

As of December 31, 2001 and 2000, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the debt's interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments based on quoted market prices, current market conditions, estimates we obtained from third-party brokers or dealers, or amounts derived using valuation models.

Trading and Non-Trading Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of December 31:

	2001	2000
	(In millions)	
Trading price risk management activities:		
Futures contracts	$ (206)	$ 149
Option contracts		
Financial instruments	553	(118)
Physical contracts[1]	897	659
Total option contracts	1,450	541
Swap and forward contracts		
Financial instruments	(107)	1,379
Physical contracts[1]	163	79
Total swap and forward contracts	56	1,458
Non-commodity contracts	(5)	52
Net assets from trading price risk management activities	1,295	2,200
Non-trading price risk management activities:		
Futures contracts	25	—
Option contracts	(17)	—
Swap and forward contracts		
Financial instruments	427	—
Physical contracts[1]	24	—
Total swap and forward contracts	451	—
Non-commodity contracts	(33)	—
Net assets from non-trading price risk management activities	426	—
Net assets from price risk management activities	$1,721	$2,200

(1) Physical contracts include transportation capacity, tolling agreements and natural gas in storage held for trading purposes.

Commodity Trading Activities

We recognized gross margins from our trading activities of $690 million and $418 million for the year ended December 31, 2001 and 2000. The fair value of commodity and energy related contracts entered into for trading purposes as of December 31, 2001 and 2000, and the average fair value of those instruments are set forth below:

	Assets	Liabilities	Average Fair Value for the Year Ended December 31,[1]
		(In millions)	
2001			
Futures contracts	$ 150	$ (356)	$ 59
Option contracts	1,832	(382)	1,723
Swap and forward contracts	2,296	(2,240)	(43)
2000			
Futures contracts	$ 152	$ (3)	$ 280
Option contracts	2,194	(1,653)	591
Swap and forward contracts	4,354	(2,896)	688

(1) Computed using the net asset (liability) balance at the end of each month.

Notional Amounts and Terms of Trading Price Risk Management Activities

The notional amounts and terms of our energy commodity financial instruments at December 31, 2001 and 2000, are set forth below:

	Fixed Price Payor	Fixed Price Receiver	Maximum Terms in Years
2001			
Energy Commodities:			
Natural gas (TBtu)	23,407	23,259	27
Power (Terawatt hours)	655	671	19
Crude oil and refined products (MMBbls)	119	77	5
Weather (thousands of degree days)	468	469	2
Energy capacity (Gigawatt hours)	33	50	12
Emissions (MTons)	148	178	1
2000			
Energy Commodities:			
Natural gas (TBtu)	34,306	29,896	27
Power (Terawatt hours)	133	143	20
Crude oil and refined products (MMBbls)	50	47	6
Weather (thousands of degree days)	133	135	—
Energy capacity (Gigawatt hours)	22	29	3

The notional amounts included in the table above reflect the contracted notional volumes multiplied by the number of delivery periods remaining under the related contracts. These notional amounts are not indicative of future cash flows as we may decide to sell the contracts into the commodity markets in the future.

The notional amount and terms of foreign currency forward purchases and sales and interest rate swaps and futures at December 31, 2001 and 2000, were as follows:

	Notional Volume		Maximum
	Buy	Sell	Term in Years
2001			
Foreign Currency (in millions)			
Canadian Dollars	401	291	10
Interest Rates (in millions)			
3-Month LIBOR	145	68	20
2000			
Foreign Currency (in millions)			
Canadian Dollars	1,095	441	8

The weighted average maturity of our entire portfolio of price risk management activities was approximately four years as of December 31, 2001, and two years as of December 31, 2000.

Market and Credit Risks

We serve a diverse group of customers that require a wide variety of financial structures, products and terms. This diversity requires us to manage, on a portfolio basis, the resulting market risks inherent in these transactions subject to parameters established by our risk management committee. We monitor market risks through a risk control committee operating independently from the units that create or actively manage these risk exposures to ensure compliance with our stated risk management policies.

We measure and adjust the risk in our portfolio in accordance with mark-to-market and other risk management methodologies which utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances (including cash in advance, letters of credit, and guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. The counterparties associated with our assets from trading price risk management activities are summarized as follows:

	Assets from Trading Price Risk Management Activities as of December 31, 2001		
	Investment Grade[1]	Below Investment Grade[1][2]	Total[3][4]
		(In millions)	
Energy marketers	$1,472	$370	$1,842
Financial institutions	349	—	349
Natural gas and oil producers	141	13	154
Natural gas and electric utilities	1,291	83	1,374
Industrials	21	18	39
Municipalities	223	—	223
Natural gas and electric utilities not publicly rated	99	2	101
Total assets from trading price risk management activities	$3,596	$486	$4,082

	Assets from Trading Price Risk Management Activities as of December 31, 2000		
	Investment Grade[1]	Below Investment Grade[1][2]	Total[3]
		(In millions)	
Energy marketers	$2,610	$ 34	$2,644
Financial institutions	1,533	—	1,533
Natural gas and oil producers	642	1	643
Natural gas and electric utilities	1,558	68	1,626
Industrials	103	2	105
Municipalities	17	—	17
Natural gas and electric utilities not publicly rated	68	1	69
Total assets from trading price risk management activities	$6,531	$106	$6,637

(1) "Investment Grade" and "Below Investment Grade" are primarily determined using publicly available credit ratings, or if a counterparty is not publicly rated, a minimum implied credit rating through internal credit analysis. "Investment Grade" includes counterparties with a minimum Standard & Poor's rating of BBB– or Moody's rating of Baa3. "Below Investment Grade" includes counterparties with a credit rating that do not meet the criteria of "Investment Grade".

(2) As of December 31, 2001, we required collateral, which encompasses margins, standby letters of credit, and parent company guarantees, for $375 million of the $486 million, or 77%, from counterparties included in "Below Investment Grade".

(3) We had one customer that comprised greater than 5 percent of assets from price risk management activities as of December 31, 2001. Although this customer was considered below investment grade, our position with this counterparty was fully collateralized through margins and standby letters of credit. We had one customer that comprised greater than 5 percent of assets from price risk management activities as of December 31, 2000. The customer was considered investment grade.

(4) Counterparty total does not include natural gas in storage or marketable securities held for trading purposes of $196 million at December 31, 2001.

This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Non-Trading Price Risk Management Activities

We also utilize derivative financial instruments for non-trading activities to mitigate market price risk associated with significant physical transactions. Non-trading commodity activities are accounted for using hedge accounting provided they meet hedge accounting criteria. Non-trading activities are conducted through exchange traded futures contracts, swaps, and forward agreements with third parties.

The notional amounts and terms of contracts held for purposes other than trading were as follows at December 31:

	2001			2000		
	Notional Volume		Maximum	Notional Volume		Maximum
	Buy	Sell	Term in Years	Buy	Sell	Term in Years
Commodity						
Natural Gas (TBtu)	28	944	12	116	676	12
Power (MMWh)	—	—	—	134	35	2
Crude oil and refined products (MMBbls)	117	116	2	11,385	13,187	1

In March 2001, we issued €550 million (approximately $510 million) of euro notes at 5.75% due 2006. To reduce our exposure to foreign currency risk, we entered into a swap transaction exchanging the euro note for a $510 million U.S. dollar denominated obligation with a fixed interest rate of 6.61% for the five-year term of the note. The fair value of our liability related to this swap was $33 million as of December 31, 2001.

As of December 31, 2001, we had an interest rate swap transaction with a notional amount of $240 million exchanging LIBOR, a variable interest rate, for a fixed rate of 3.07%. This swap was entered into as a hedge of the variable interest rates on a loan with a principal amount of $240 million that matures in March 2004. The swap converts the variable interest payments on the loan to a fixed rate of 4.49% until the swap terminates in June 2003. The fair value of this swap was immaterial as of December 31, 2001.

We also face credit risk with respect to our non-trading activities, and take similar measures as in our trading activities to mitigate this risk. Based upon our policies and risk exposure, we do not anticipate a material effect on our financial position, operating results or cash flows resulting from counterparty non-performance.

9. Accounting for Hedging Activities

On January 1, 2001, we adopted the provisions of SFAS No. 133 and recorded a cumulative-effect adjustment of $1,280 million, net of income taxes, in accumulated other comprehensive income to recognize the fair value of all derivatives designated as hedging instruments. The majority of the initial charge related to hedging cash flows from anticipated sales of natural gas for 2001 and 2002. During the year ended December 31, 2001, $1,063 million, net of income taxes, of this initial transition adjustment was reclassified to earnings as a result of hedged sales and purchases during the year. A discussion of our hedging activities is as follows:

Fair Value Hedges. We have crude oil and refined products inventories that change in value daily due to changes in the commodity markets. We use futures and swaps to protect the value of these inventories. For the year ended December 31, 2001, the financial statement impact of our hedges of the fair value of these inventories was immaterial.

Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. As of December 31, 2001, the value of cash flow hedges included in accumulated other comprehensive income was a net unrealized gain of $256 million, net of income taxes. We estimate that unrealized gains of $272 million, net of income taxes, will be reclassified from accumulated other comprehensive income over the next 12 months. Reclassifications occur upon physical delivery of the hedge commodity and the corresponding expiration of the hedge. The maximum term of our cash flow hedges is 12 years; however, most of our cash flow hedges expire within the next 24 months.

Our accumulated other comprehensive income also includes a loss of $23 million, net of income taxes, representing our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates who use derivatives as cash flow hedges. Included in this loss is a $10 million loss that we estimate will be reclassified from accumulated other comprehensive income over the next 12 months. The maximum term of these cash flow hedges is two years, excluding hedges related to interest rates on variable debt.

For the year ended December 31, 2001, we recognized a net gain of $3 million, net of income taxes, related to the ineffective portion of all cash flow hedges.

Foreign Currency Hedges. In our international activities, we have fixed rate foreign currency denominated debt that exposes us to changes in exchange rates between the foreign currency and U.S. dollar. In 2001, we used a currency swap to effectively convert the fixed amounts of foreign currency due under foreign currency denominated debt to fixed U.S. dollar amounts.

10. Inventory

Our inventory consisted of the following at December 31:

	2001	2000
	(In millions)	
Refined products, crude oil and chemicals	$577	$1,004
Coal, materials and supplies and other	207	273
Natural gas in storage	41	58
Total	$825	$1,335

11. Property, Plant and Equipment

At December 31, 2001 and 2000, we had approximately $2,271 million and $2,367 million construction work in progress included in our property, plant and equipment.

In June 2001, we entered into a 20-year lease agreement related to our Corpus Christi refinery and related assets with Valero Energy Corporation. Under the lease, Valero pays us a quarterly amount that increases after the second year of the lease. For the year ended December 31, 2001, we recorded $11 million in lease income related to this lease. In addition, Valero has the option to purchase the plant and related assets in 2003 for approximately $294 million, and a similar option each year thereafter at an annually increasing amount. The net book value of the plant and related assets was approximately $225 million at December 31, 2001. Based on the terms, the lease qualified as an operating lease with total minimum lease payments of $811 million with future minimum lease payments totaling $797 million; $19 million in 2002; $37 million in 2003; $43 million in each of 2004, 2005 and 2006; and a total of $612 million thereafter.

12. Debt, Other Financing Obligations and Other Credit Facilities

At December 31, 2001, our weighted average interest rate on our commercial paper and short-term credit facilities was 3.2%, and at December 31, 2000, it was 7.4%. We had the following short-term borrowings and other financing obligations, at December 31:

	2001	2000
	(In millions)	
Commercial paper	$1,265	$1,416
Short-term credit facilities	111	805
Current maturities of long-term debt and other financing obligations	1,799	1,328
Notes payable	139	80
	$3,314	$3,629

Credit Facilities

We use commercial paper programs to manage our short-term cash requirements. Under our programs we can borrow up to $3 billion through a combination of individual corporate, TGP and EPNG commercial paper programs of $1 billion each.

We maintain a 3-year, $1 billion, revolving credit and competitive advance facility under which we can conduct short-term borrowings and other commercial credit transactions. This facility expires in 2003 and El Paso CGP (formerly Coastal), EPNG and TGP are designated borrowers under the facility. In June 2001, we replaced an existing 364-day revolving credit facility with a renewable $3 billion, 364-day revolving credit and competitive advance facility. EPNG and TGP are also designated borrowers under this new facility. The interest rate on these facilities varies and was based on LIBOR plus 50 basis points at December 31, 2001. No amounts were outstanding under these facilities at December 31, 2001.

In connection with our acquisition of PG&E's Texas Midstream operations in December 2000, we established a $700 million short-term credit facility, under which $455 million was outstanding on December 31, 2000. In February 2001, we borrowed an additional $245 million under the facility. In two separate payments in March and June 2001, we repaid the outstanding balance of the credit facility, and the facility was terminated.

We also supplement our commercial paper program with other smaller short-term credit facilities, some of which were used by Coastal prior to our merger and which were terminated during the year.

In April 2001, we filed a shelf registration statement with the Securities and Exchange Commission to sell, from time to time, up to a total of $3 billion in debt securities, preferred and common stock, medium term notes, or trust securities. At December 31, 2001, we had approximately $920 million remaining from this shelf registration statement under which we issued additional securities in January 2002.

As of December 31, 2001, TGP had $200 million, and SNG had $100 million under shelf registration statements on file with the Securities and Exchange Commission.

The availability of borrowings under our credit and borrowing agreements is subject to specified conditions, which we believe we currently meet. These conditions include compliance with the financial covenants and ratios required by such agreements, absence of default under such agreements, and continued accuracy of the representations and warranties contained in such agreements. Our senior unsecured debt issues have been given investment grade ratings by S&P and Moody's.

2002 Activities

In January 2002, we increased our shelf registration statement from $920 million to $1.10 billion and issued $1.10 billion aggregate principal amount of 7.75% medium term notes due 2032. Net proceeds of approximately $1.08 billion, net of issuance costs, were used to repay short-term borrowings and for general corporate purposes. This issuance used up the remaining capacity on our previous shelf registration statement. In February 2002, we filed a new shelf registration statement with the Securities and Exchange Commission that allows us to issue up to $3 billion. Under this registration statement we can issue a combination of debt, equity and other instruments, including trust preferred securities of El Paso Capital Trust II and El Paso Capital Trust III, trusts wholly owned by us. If we issue securities from these trusts, we will be required to issue full and unconditional guarantees on these securities.

Also in January 2002, we retired $100 million aggregate principal amount 7.85% notes and $215 million aggregate principal amount 7.75% notes. In March 2002, we retired $400 million of floating rate notes.

In January 2002, SNG filed a shelf registration statement increasing the amount of debt it can issue from $100 million to $300 million. In February 2002, SNG issued $300 million aggregate principal amount of 8.0% notes due 2032. Net proceeds of approximately $297 million, net of issuance costs, were used for general corporate purposes. This issuance used the remaining capacity on SNG's shelf registration statement.

Our long-term debt and other financing obligations outstanding consisted of the following at December 31:

	2001	2000
	(In millions)	
Long-term debt		
El Paso Corporation		
Senior notes, 5.75% through 6.75%, due 2001 through 2009	$ 1,010	$ 1,100
Notes, 6.625% through 9.0%, due 2001 through 2030	1,600	1,200
Medium-term notes, 6.95% through 8.05%, due 2007 through 2031	1,600	900
Zero coupon convertible debentures due 2021	827	—
Variable rate senior note due 2001, average interest for 2000 of 7.11%	—	100
El Paso Tennessee		
Notes, 7.25% through 10.0%, due 2008 through 2025	51	51
Debentures, 6.5% through 10.0%, due 2001 through 2005	12	36
Tennessee Gas Pipeline		
Debentures, 6.0% through 7.625%, due 2011 through 2037	1,386	1,386
El Paso Natural Gas		
Notes, 6.75% through 7.75%, due 2002 through 2003	415	415
Debentures, 7.5% and 8.625%, due 2022 and 2026	460	460
Southern Natural Gas		
Notes, 6.125% through 8.875%, due 2001 through 2031	700	500
EPEC Corporation		
Senior Note, 9.625%, due 2001	—	13
Field Services		
Notes, 7.41% through 11.5% due 2001 through 2012	164	511
El Paso CGP		
Notes payable (revolving credit agreement)	—	135
Senior notes, 6.2% through 10.375%, due 2001 through 2010	1,565	1,650
Floating rate senior notes, due 2002 through 2003	600	600
Senior debentures, 6.375% through 10.75%, due 2003 through 2037	1,497	1,497
FELINE PRIDES, 6.625%, due 2004	460	460
Valero lease financing loan due 2004	240	—
El Paso Production Company		
Floating rate notes, due 2005 and 2006	200	100
ANR Pipeline		
Debentures, 7.0% through 9.625%, due 2021 through 2025	500	500
Colorado Interstate Gas		
Debentures, 6.85% through 10.0%, due 2005 and 2037	280	280
Other	408	234
	13,975	12,128
Less:		
Unamortized discount	75	47
Current maturities	1,209	1,179
Long-term debt, less current maturities	12,691	10,902
Other Financing Obligations		
Crude oil prepayments	500	500
Natural gas production payment	215	350
	715	850
Less:		
Current maturities	590	149
Other financing obligations, less current maturities	125	701
Total long-term and other financing obligations, less current maturities	$12,816	$11,603

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2002	$ 1,799
2003	586
2004	1,027
2005	561
2006	1,276
Thereafter	9,441
Total long-term debt and other financing obligations, including current maturities	$14,690

Our zero coupon convertible debentures have a maturity value of $1.8 billion, are due 2021 and have a yield to maturity of 4%. These debentures are convertible into 8,456,589 shares of our common stock, which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate is equal to a conversion price of $94.604 per share of our common stock.

In October 2001, we borrowed $240 million due in 2004 under a loan agreement. The loan is collateralized by the lease payments from Valero under their lease of our Corpus Christi refinery.

In 1999, we issued a total of 18,400,000 FELINE PRIDES[sm] consisting of 17,000,000 Income PRIDES with a stated value of $25 and 1,400,000 Growth PRIDES with a stated value of $25. The Income PRIDES consist of a unit comprised of a Senior Debenture and a purchase contract under which the holder is obligated to purchase from us by no later than August 16, 2002 for $25 (the stated price) a number of shares of our common stock. The Growth PRIDES consist of a unit comprised of a purchase contract under which the holder is obligated to purchase from us by no later than August 16, 2002 for $25 (the stated price) a number of shares of our common stock and a 2.5% undivided beneficial interest in a three-year Treasury security having a principal amount at maturity equal to $1,000. Under the terms of the purchase contract in effect prior to our merger with Coastal, the number of shares of common stock the holder of a PRIDE received varied between 0.5384 and 0.6568 shares, depending on the price of Coastal's common stock.

As a result of our merger with Coastal, and under the terms of the purchase contract, the number of shares the holder of a PRIDE is entitled and required to receive upon settlement became fixed at 0.6622 shares of El Paso common stock. This will result in the issuance of approximately 12.2 million shares of El Paso common stock.

Our other financing obligations consist of crude oil prepayments received from third parties in exchange for our agreement to deliver a fixed quantity of crude oil to a specified delivery point in the future and a production payment received in exchange for delivery of a fixed quantity of natural gas from our future production. These agreements, by their terms, can only be settled through the delivery of the commodity. We have entered into commodity swaps to effectively lock-in the value of these commitments to the third party upon delivery of the commodity. We will continue to deliver natural gas under the production payment agreement according to its terms, but consider these agreements to be financing arrangements. The carrying cost of the prepayments and the production payment are recognized as interest expense in our income statement.

13. Securities of Subsidiaries and Minority Interests

Over the past three years, we have entered into a number of transactions to finance our consolidated subsidiaries. In most cases, these have been accomplished through the sale of preferred interests in these entities, or through structured financial transactions that are collateralized by the assets of these subsidiaries. Total amounts outstanding under these programs at December 31, 2001, were as follows (in millions):

Consolidated trusts[(1)]	$ 925
Trinity River	980
Clydesdale	1,000
Preferred stock of subsidiaries	465
Gemstone	300
Consolidated partnership	285
Other	58
	$4,013

(1) The consolidated trusts are composed of Capital Trust I, Coastal Finance I and Capital Trust IV.

Capital Trust I. In March 1998, we formed El Paso Energy Capital Trust I which issued 6.5 million of 4³⁄₄% trust convertible preferred securities for $325 million. We own all of the Common Securities of Trust I. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4³⁄₄% convertible subordinated debentures due 2028, their sole asset. We provide a full and unconditional guarantee of Trust I's preferred securities. Trust I's preferred securities are reflected as company-obligated preferred securities of consolidated trusts in our balance sheet. Distributions paid on the preferred securities are included as minority interest in our income statement.

Trust I's preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4³⁄₄%, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I Preferred Security (equivalent to a conversion price of $41.59 per common share). As of December 31, 2001, we had approximately 6.5 million Trust I preferred securities outstanding.

Coastal Finance I. In May 1998, Coastal completed a public offering of 12 million mandatory redemption preferred securities on Coastal Finance I, a business trust, for $300 million. Coastal Finance I holds debt securities of ours purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375% of the liquidation amount of $25 per preferred security. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at our option on or after May 13, 2003, or earlier if various events occur. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption.

Capital Trust IV. In May 2000, we formed El Paso Energy Capital Trust IV which issued $300 million of preferred securities to a third party investor. These preferred securities pay cash distributions at a floating rate equal to the three-month LIBOR plus 75 basis points. As of December 31, 2001, the floating rate was 2.83%. These preferred securities must be redeemed by Trust IV no later than November 30, 2003. Proceeds from the sale of the securities were used by Trust IV to purchase a series of our floating rate senior debentures whose yield and maturity terms mirror those of Trust IV's preferred securities. The sole assets of Trust IV are these floating rate senior debentures. We provide a full and unconditional guarantee of all obligations of Trust IV related to its preferred securities. At the time Trust IV issued the preferred securities, we also agreed to issue $300 million of equity securities, including, but not limited to, our common stock in one or more public offerings prior to May 31, 2003.

Trinity River (also known as Red River). During 1999, we formed a series of companies that we refer to as Trinity River. Trinity River was formed to provide financing to invest in various capital projects and other assets. A third-party investor contributed cash of $980 million into Trinity River during 1999 in exchange for the preferred securities of one of our consolidated subsidiaries. The third party is entitled to an adjustable preferred return derived from Trinity River's net income. The preferred interest is collateralized by a combination of notes payable from us and various fixed assets, including our Mojave pipeline, Bear Creek Storage, various natural gas and oil production properties and some of our El Paso Energy Partners common units. We have the option to acquire the third-party's interest in Trinity River at any time prior to June 2004.

If we do not exercise this option or if the agreement is not extended, we could be required to liquidate the assets supporting this transaction. We account for the investor's preferred interest in our consolidated subsidiary as a minority interest in our balance sheet and the preferred return as minority interest expense in our income statement. The assets, liabilities and operations of Trinity River are included in our financial statements. If our credit ratings are downgraded to below investment grade by both S&P and Moody's, we could be required to liquidate the assets supporting the transaction.

Clydesdale (also known as Mustang). During 2000, we formed a series of companies that we refer to as Clydesdale. Clydesdale was formed to provide financing to invest in various capital projects and other assets. A third-party investor contributed cash of $1 billion into Clydesdale in exchange for the preferred securities of one of our consolidated subsidiaries. The third party is entitled to an adjustable preferred return derived from Clydesdale's net income. The preferred interest is collateralized by a combination of notes payable from us and various fixed assets, including our Colorado Interstate Gas transmission system and natural gas and oil properties. We have the option to acquire the third-party's interest in Clydesdale at any time prior to May 2005. If we do not exercise this option or if the agreement is not extended, we could be required to liquidate the assets supporting this transaction. We account for the investor's preferred interest in our consolidated subsidiary as a minority interest in our balance sheet and the preferred return as minority interest expense in our income statement. The assets, liabilities, and operations of Clydesdale are included in our financial statements. If our credit ratings are downgraded to below investment grade by both S&P and Moody's, we could be required to liquidate the assets supporting the transaction.

El Paso Tennessee Preferred Stock. In 1996, El Paso Tennessee Pipeline Co., our subsidiary, issued 6 million shares of publicly registered 8.25% cumulative preferred stock with a par value of $50 per share for $300 million. The preferred stock is redeemable, at the option of El Paso Tennessee, at a redemption price equal to $50 per share, plus accrued and unpaid dividends, at any time after January 2002. During the three years ended December 31, 2001, dividends of approximately $25 million were paid each year on the preferred stock.

Coastal Securities Company Preferred Stock. In 1996, Coastal Securities Company Limited, our wholly owned subsidiary, issued 4 million shares of preferred stock for $100 million. Quarterly cash dividends are being paid on the preferred stock at a rate based on LIBOR. The preferred shareholders are also entitled to participating dividends based on various refining margins. Coastal Securities may redeem the preferred stock for cash at the liquidation price plus accrued and unpaid dividends.

Coastal Oil & Gas Resources Preferred Stock. In 1999, Coastal Oil & Gas Resources, Inc., our wholly owned subsidiary, issued 50,000 shares of preferred stock for $50 million. The preferred shareholders are entitled to quarterly cash dividends at a rate based on LIBOR. The dividend rate is subject to renegotiation in 2004 and on each fifth anniversary thereafter. In the event Coastal Oil & Gas Resources and the preferred shareholders are unable to agree to a new rate, Coastal Oil & Gas Resources must redeem the shares at $1,000 per share plus any accrued and unpaid dividends, or cause the preferred stock to be registered with the Securities and Exchange Commission and remarketed. Coastal Oil & Gas Resources also has the option to redeem all shares on any dividend rate reset date for $1,000 per share plus any accrued and unpaid preferred dividends.

Coastal Limited Ventures Preferred Stock. In 1999, Coastal Limited Ventures, Inc., our wholly owned subsidiary, issued 150,000 shares of preferred stock for $15 million. The preferred shareholders are entitled to quarterly cash dividends at an annual rate of 6%. The dividend rate is subject to renegotiation in 2004 and on each fifth anniversary thereafter. In the event Coastal Limited and the preferred shareholders are unable to agree to a new rate, the preferred shareholders may call for redemption of all of the preferred shares. The redemption price is $100 per share plus any accrued and unpaid preferred dividends thereon. Coastal Limited also has the option to redeem all shares on any rate reset date for $100 per share plus any accrued and unpaid preferred dividends.

Gemstone. As part of the Gemstone transaction, our wholly owned subsidiary, Topaz Investors, L.L.C., issued a minority member interest to the third party investor of Gemstone for $300 million. The third party investor is entitled to a cumulative preferred return of 8.03% on its interest. The agreements underlying this transaction expire in 2004, or earlier if we sell the international power assets owned indirectly by Topaz. The minority member interest is redeemable at liquidation value plus accrued and unpaid dividends.

Consolidated Partnership. In December 1999, Coastal Limited contributed assets to a limited partnership in exchange for a controlling general partnership interest. Limited interests in the partnership were issued to unaffiliated investors for $285 million. The limited partners are entitled to a cumulative priority return based on LIBOR. The return is subject to renegotiation in 2004 and on each fifth anniversary thereafter. The partnership has a maximum life of 20 years, but may be terminated sooner subject to certain conditions, including failure to agree to a new rate. Coastal Limited may terminate the partnership at any time by repayment of the limited partners' outstanding capital plus any unpaid priority returns.

14. Commitments and Contingencies

Legal Proceedings

We and several of our subsidiaries were named defendants in eleven purported class action, municipal or individual lawsuits, and in one shareholder derivative lawsuit, filed in the California state courts. The eleven suits contend that our entities acted improperly to limit the construction of new pipeline capacity to California and/or to manipulate the price of natural gas sold into the California marketplace. The shareholder derivative suit contends that we, through our directors, failed to prevent the conduct alleged in several of these underlying cases. We have consolidated nine of the eleven suits into a single San Diego court proceeding, and expect to consolidate the remaining two suits in the near future. In March 2002, the derivative lawsuit was dismissed in California, to be refiled in a state court in Houston, Texas. A listing of these cases is included under the heading *Cases* below.

In September 2001, we received a civil document subpoena from the California Department of Justice, seeking information said to be relevant to the Department's ongoing investigation into the high electricity prices in California. We have produced and expect to continue to produce materials pursuant to this subpoena.

On August 19, 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. On June 20, 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Proposed Violation to EPNG. The Notice alleged five probable violations of its regulations, proposed fines totaling $2.5 million and proposed corrective actions. On October 15, 2001, EPNG filed a detailed response with the Office of Pipeline Safety disputing each of the alleged violations. The alleged five probable violations of the regulations of the Department of Transportation's Office of Pipeline Safety are: 1) failure to perform appropriate tasks to prevent corrosion, with an associated proposed fine of $500,000; 2) failure to investigate and minimize internal corrosion, with an associated proposed fine of $1,000,000; 3) failure to consider unusual operating and maintenance conditions and respond appropriately, with an associated proposed fine of $500,000; 4) failure to follow company procedure, with an associated proposed fine of $500,000; and 5) failure to maintain topographical diagrams, with an associated proposed fine of $25,000. We are cooperating with the National Transportation Safety Board in an investigation into the facts and circumstances concerning the possible causes of the rupture. If we are required to pay the proposed fines, it will not have a material adverse effect on our financial position, operating results or cash flows. In addition, a number of personal injury and wrongful death lawsuits were filed against us in connection with the rupture. Several of these suits have been settled, with payments fully covered by insurance. Seven Carlsbad lawsuits remain, with one of those seven having reached a contingent settlement within insurance coverage. A listing of these cases is included under the heading *Cases* below.

In May 1999, one of our subsidiaries was named as a defendant in a suit filed in the 319th Judicial District Court, Nueces County, Texas by an individual employed by one of our contractors *(Rolando Lopez and Rosanna Barton v. Coastal Refining & Marketing, Inc. and The Coastal Corporation)*. The suit sought damages for injuries sustained at the time of an explosion at one of our refining plants, and was settled in August 2000 for a total payment of $7 million, of which $5 million was covered by insurance. Three of the refinery employees intervened in the suit and sought damages for injuries sustained in the explosion. Those claims were tried in August 2000, resulting in a $122 million verdict, for which there is insurance coverage.

The case has been appealed to the Thirteenth Court of Appeals of Texas, and all appellate briefing in that court has been completed. Even if the verdict is upheld on appeal, it will not have a material adverse effect on our financial position, operating results or cash flows.

In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to under report the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. These matters have been consolidated for pretrial purposes (In re: natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss.

A number of our subsidiaries were named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors. et al,* filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings. A motion to dismiss this case is pending.

In October 1992, several property owners in McAllen, Texas, filed suit in the 93rd Judicial District Court, Hidalgo County, Texas, against, among others, one of our subsidiaries (*Timely Adventures, Inc., et al,* v. *Phillips Properties, Inc., et al* and *Garza* v. *Coastal Mart, Inc.*). The suit sought damages for the alleged diminution of property value and damages related to the exposure to hazardous chemicals arising from the operation of service stations and storage facilities. In July 2000, the trial court entered a judgment for approximately $1.2 million in actual damages for property diminution and approximately $100 million in punitive damages. The judgment was appealed. An agreement in principle to settle this case has been reached, and we expect the settlement to be concluded in March 2002. We have established accruals that we believe are sufficient to provide for the settlement. The settlement will not have a material adverse effect on our financial position, operating results or cash flows.

In compliance with the 1990 amendments to the Clean Air Act (CAA), we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in five such lawsuits in New York. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In addition, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. For each of these matters, we evaluate the merits of the case, our exposure to the matter and possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we make the necessary accruals. As new information becomes available, our estimates may change. The impact of these changes may have a material effect on our results of operations. As of December 31, 2001, we had reserves totaling $187 million for all outstanding legal matters.

While the outcome of the matters discussed above cannot be predicted with certainty, based on information known to date and our existing accruals, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, operating results or cash flows.

Environmental Matters

We are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2001, we had a reserve of approximately $555 million for expected remediation costs, including approximately $526 million for associated onsite, offsite and groundwater technical studies, and approximately $29 million for other costs which we anticipate incurring through 2027. In addition, we expect to make capital expenditures for environmental matters of approximately $333 million in the aggregate for the years 2002 through 2006. These expenditures primarily relate to compliance with clean air regulations. Our accrued amounts as of December 31, 2001 include a change in our estimated environmental remediation liabilities as a result of several events that occurred during 2001 and an evaluation of our operations following the Coastal merger. See a discussion of this change in estimate under *Changes in Accounting Estimates*.

In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of polychlorinated biphenyls (PCBs) without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs and a civil penalty. TGP entered into agreed orders with the agency to resolve many of the issues raised in the complaint and received water discharge permits from the agency for its Kentucky compressor stations. The relevant Kentucky compressor stations are being characterized and remediated under a 1994 consent order with the Environmental Protection Agency (EPA). Despite these remediation efforts, the agency may raise additional technical issues or require additional remediation work in the future.

From May 1999 to March 2001, our Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection. All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The New Jersey Department of Environmental Protection has assessed penalties totaling approximately $1.1 million for these alleged violations. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments and, concurrently, is in negotiations to settle these assessments.

In February 2002, we received a Notice of Violation from the EPA alleging noncompliance with the EPA's fuel regulations from 1996 to 1998. The notice proposes a penalty of $165,000 for these alleged violations. We are investigating the allegations and are preparing a response.

Since 1988, TGP has been engaged in an internal project to identify and deal with the presence of PCBs and other substances, including those on the EPA List of Hazardous Substances, at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders, to ensure that its efforts meet regulatory requirements.

In May 1995, following negotiations with its customers, TGP filed a stipulation and agreement with FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal project. The stipulation and agreement was effective July 1, 1995. Refunds may be required to the extent actual eligible expenditures are less than amounts collected.

TGP is a party in proceedings involving federal and state authorities regarding the past use of PCBs in its starting air systems. TGP executed a consent order in 1994 with the EPA governing the remediation of the relevant compressor stations and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at the Pennsylvania and New York stations.

We have been designated, have received notice that we could be designated or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 57 active sites under CERCLA or state equivalents. We have sought to resolve our liability as a PRP at these CERCLA sites, as appropriate, through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2001, we have estimated our share of the remediation costs at these sites to be between $66 million and $205 million and have provided reserves that we believe are adequate for such costs. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in the determination of our estimated liabilities. We presently believe that based on our existing reserves, and information known to date, the impact of the costs associated with these CERCLA sites will not have a material adverse effect on our financial position, operating results or cash flows.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations, and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe the recorded reserves are adequate.

Rates and Regulatory Matters

In April 2000, the California Public Utilities Commission (CPUC) filed a complaint with FERC alleging that the sale of approximately 1.2 Bcf/d of California capacity by EPNG to El Paso Merchant Energy Company, both of whom are our wholly-owned subsidiaries, was anti-competitive and an abuse of the affiliate relationship under FERC's policies. Other parties in the proceeding requested that the original complaint be set for hearing and that Merchant Energy pay back any profits it earned under the contract. In March 2001, FERC established a hearing, before an administrative law judge, to address the issue of whether EPNG and/or Merchant Energy had market power and, if so, had exercised it. In October 2001, the administrative law judge issued a proposed decision finding that El Paso did not exercise market power and that the market power portion of the CPUC's complaint should be dismissed. The decision further found that El Paso had violated FERC's marketing affiliate regulations. The judge's proposed decision has been briefed to, and will be effective only if approved by, the FERC. On October 30, 2001, the Market Oversight and Enforcement (MOE) section of the FERC's office of the General Counsel filed comments in this proceeding stating that record development at the trial was inadequate to conclude that EPNG complied with FERC's regulation. We filed a motion to strike the MOE's pleading, but in December 2001, the FERC denied our motion and remanded the proceeding to the administrative law judge for a supplemental hearing on the availability of capacity at El Paso's California delivery points. The hearing is set to commence on March 20, 2002.

Two groups of EPNG's customers, those within California and those east of California, have filed complaints against EPNG with FERC. On July 13, 2001, twelve parties composed of California customers, natural gas producers and natural gas marketers, filed a complaint alleging that EPNG's full requirements contracts with its customers east of California should be converted to contracts with specific volumetric entitlements, that EPNG should be required to expand its interstate pipeline system and that firm shippers who experience reductions in their nominated gas volumes should be awarded demand charge credits. Also, on July 17, 2001, ten parties, most of which are east of California full-requirement contract customers, filed a complaint against EPNG with FERC, alleging that EPNG violated the Natural Gas Act of 1938 and breached its contractual obligations by failing to expand its system in order to serve the needs of the full-requirement contract shippers. The complainants have requested that FERC require EPNG to show cause why it should not be required to augment its system capacity. On September 10, 2001, the July 17, 2001 complainants filed a motion for partial summary disposition of their complaint, to which EPNG responded on September 25, 2001. In addition, on November 13, 2001, one of the July 17, 2001, complainants submitted a type of settlement proposal that we and most other parties have opposed. At its March 13, 2002 public meeting, the FERC Staff made a presentation to the FERC Commissioners recommending that FERC address the capacity allocation issues raised in these and other related EPNG proceedings by, among other things, eliminating the full requirements provisions from all of EPNG's contracts except those in a small customer category and converting them to contracts with specific volumetric entitlements. The Staff also recommended scheduling a technical conference. FERC authorized its Staff to provide notice of a technical conference to be attended by the Commissioners. It is expected that this conference will be held no later than the spring of this year.

In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust, in which we have a 33 percent ownership interest and a total investment, including financial guarantees, of approximately $182 million. EPIC Energy Australia has appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The appeal was heard at the Western Australia Supreme Court in November 2001 and a decision from the court is expected in the middle of 2002. If the draft decision rates are implemented, the new rates will adversely impact future operating results, liquidity and debt capacity, possibly reducing the value of our investment by up to $122 million.

In September 2001, FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place additional administrative and operational burdens on us.

While we cannot predict with certainty the final outcome or the timing of the resolution of all of our rates and regulatory matters, we believe the ultimate resolution of these issues, based on information known to date, will not have a material adverse effect on our financial position, results of operations or cash flows.

Other Matters

In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We had contracts with Enron North America, Enron Power Marketing and other Enron subsidiaries for, among other things, the transportation of natural gas and natural gas liquids, the trading of physical gas, power, petroleum and financial derivatives. We established reserves for potential losses related to the receivables from our transportation contracts, as well as the positions and receivables under our marketing and trading contracts that we believe are adequate. In addition, we have terminated most of our trading related contracts as a result of Enron's bankruptcy filings, and are analyzing our damage claims arising from the Enron bankruptcy proceedings.

Affiliates of Enron hold both short-term and long-term capacity on several of our pipeline systems. As a result of Enron's bankruptcy filing, we are uncertain as to their intent to maintain or release this capacity and also as to their ability to honor the terms of their contracts. Future revenue related to these capacity contracts will depend upon the outcome of Enron's bankruptcy proceedings and our ability to re-market any subsequently released pipeline capacity. While we expect to re-market any such capacity on favorable terms, we cannot at this time predict that we will be successful in this effort, or that the rates we will receive will be as high as those we currently earn.

Our foreign investments are subject to risks and unforeseen obstacles that, in many cases are beyond our control or ability to manage. We attempt to manage or limit these risks through our due diligence and partner selection processes, through the denomination of foreign transactions, where possible, in U.S. dollars, and by maintaining insurance coverage, whenever economical and obtainable.

We currently have three power plants in Pakistan, with a total investment, including financial guarantees on these projects, of approximately $271 million. While we are aware of no specific threats or actions against these power plants, events in that region, including possible retaliation for American military actions, could impact these projects and our related investments. At this time, we believe that through a combination of commercial insurance, political insurance and rights under contractual obligations, our financial exposure in Pakistan from acts of war, hostility, terrorism or political instability is not material. It is possible, however, that new information, future developments in the region, or the inability of a party or parties to fulfill their contractual obligations could cause us to reassess our potential exposure.

We also have investments in oil and natural gas, power and pipeline projects in Argentina with an aggregate investment, including financial guarantees, of approximately $381 million. Economic conditions in Argentina have significantly deteriorated during 2001, and the Argentine government has recently defaulted on its public debt obligations. In addition, the government has imposed several changes in law in the first quarter of 2002, including: (i) repeal of the one-to-one exchange rate for the Argentine Peso with U.S. dollar; (ii) a mandate that all contracts and obligations previously denominated in U.S. dollars be re-negotiated and denominated in Argentine Pesos; and (iii) a tax imposed on hydrocarbon and potentially on electric power exports. The Argentine Peso devaluation, combined with the new law changes, effectively convert our projects' contracts from U.S. dollars to Argentine Pesos and will result in a significant reduction in the value of our investments in Argentina. We are monitoring the situation closely and will pursue all options available to us under our political risk insurance policies and under the international arbitration provisions of the United States — Argentina Bilateral Investment Treaty. Despite the current actions by project management and the options available to us that may mitigate our exposure, we may be required to write down our investment by a substantial amount in the first quarter of 2002.

Cases

The California cases discussed above are: five filed in the Superior Court of Los Angeles County *(Continental Forge Company. et al v. Southern California Gas Company, et al,* filed September 25, 2000; *Berg v. Southern California Gas Company, et al;* filed December 18, 2000; *County of Los Angeles v Southern California Gas Company, et al,* filed January 8, 2002; *The City of Los Angeles, et al v. Southern California Gas Company, et al* and *The City of Long Beach, et al v. Southern California Gas Company, et al,* both filed March 20, 2001); two filed in the Superior Court of San Diego County *(John W.H.K. Phillip v. El Paso Merchant Energy;* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000); three filed in the Superior Court of San Francisco County *(Sweetie's et al v. El Paso Corporation, et al,* filed March 22, 2001; *Philip Hackett, et al v. El Paso Corporation, et al,* filed May 9, 2001; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001); and one filed in the Superior Court of the State of California, County of Alameda *(Dry Creek Corporation v. El Paso Natural Gas Company, et al,* filed December 10, 2001). The shareholder derivative suit now dismissed was styled *Clark, et al v. Allumbaugh, et al,* Superior Court of Orange County, filed August 23, 2001.

The six remaining *Carlsbad* lawsuits discussed above are as follows: one filed in district court in Harris County, Texas *(Geneva Smith, et al v. EPEC and EPNG,* filed October 23, 2000), and five filed in state district court in Carlsbad, New Mexico (*Chapman, as Personal Representative of the Estate of Amy Smith Heady, v. EPEC, EPNG and John Cole,* filed February 9, 2001; *Chapman, as Personal Representative of the Estate of Dustin Wayne Smith, v. EPEC, EPNG and John Cole; Chapman, as Personal Representative of the Estate of Terry Wayne Smith, v. EPNG, EPEC and John Cole; Rackley, as Personal Representative of the Estate of Glenda Gail Sumler, v. EPEC, EPNG and John Cole; and Rackley, as Personal Representative of the Estate of Amanda Sumler Smith, v. EPEC, EPNG and John Cole,* all filed March 16, 2001). We have reached a contingent settlement in an additional case (*Dawson, as Personal Representative of Kirsten Janay Sumler, v. EPEC and EPNG,* filed November 8, 2000).

Capital Commitments, Purchase and other Obligations

At December 31, 2001, we had capital and investment commitments of $2.4 billion primarily relating to our production, pipeline, and international power activities. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures. Our pipelines have entered into unconditional purchase obligations for products and services totaling $346 million at December 31, 2001. The annual obligations under these agreements are $34 million for 2002, $32 million for 2003, $34 million for each of the years 2004, 2005 and 2006, and $178 million in total thereafter.

Operating Leases

We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2002 until 2053. As of December 31, 2001, our total commitments under operating leases were approximately $677 million.

Under several of our leases, we have provided residual value guarantees to the lessor. Under these guarantees, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is typically equal to the outstanding loan amounts owed by the lessor, or we can choose to assist in the sale of the leased asset to a third party. Should the asset not be sold for a price that equals or exceeds the amount of the guarantee, we would be obligated for the shortfall. The levels of our residual value guarantees range from 86.0 percent to 89.9 percent of the original cost of the leased assets. For the total outstanding residual value guarantees on our operating leases at December 31, 2001, see *Residual Value Guarantees* below.

Minimum annual rental commitments at December 31, 2001, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2002	$115
2003	99
2004	82
2005	67
2006	55
Thereafter	259
Total	$677

Aggregate minimum commitments have not been reduced by minimum sublease rentals of approximately $16 million due in the future under noncancelable subleases.

Rental expense on our operating leases for the years ended December 31, 2001, 2000, and 1999 was $147 million, $198 million, and $157 million.

Lines of Credit

We have a commitment to loan Mesquite, a subsidiary of Chaparral and our affiliate, up to $725 million. As of December 31, 2001, Mesquite had borrowed $552 million under this facility, resulting in undrawn commitment of $173 million. The interest rate on the facility is based on LIBOR plus a margin, and was 2.64% at December 31, 2001.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2001, we had outstanding letters of credit of $465 million related to our marketing and trading activities, our domestic power development and other operating activities.

Guarantees

Our involvement in joint ventures and project level construction and finance results in the issuance of financial and non-financial guarantees in our business activities. We also guarantee performance and contractual commitments of companies within our consolidated group. There are various events and circumstances that may require us to perform under our guarantees, including:

- non-payment by the guaranteed party;
- non-compliance with the covenants of the transactions by the guaranteed party;

- non-compliance by us with the provision of guarantees; and
- cross-acceleration with other transactions.

As of December 31, 2001, we had approximately $1.5 billion of guarantees in connection with our international development and operating activities not consolidated on our balance sheet and approximately $1.9 billion of guarantees in connection with domestic development and operating activities not consolidated on our balance sheet. Of these amounts, approximately $950 million relates to our Gemstone investment and $1.0 billion relates to our Chaparral investment.

Residual Value Guarantees

As of December 31, 2001, we have $738 million of residual value guarantees supporting our operating leases. These leases expire in 2002 and 2006.

Other Commercial Commitments

From May to October 2001, we entered into agreements to time charter four separate ships to secure transportation for our developing liquefied natural gas business. The agreements provide for deliveries of vessels between 2003 to 2005. Each time charter has a 20-year term commencing when the vessels are delivered with the possibility of two 5-year extensions. The total commitment under the four time charter agreements is $1.8 billion.

15. Retirement Benefits

Pension Benefits

We maintain a defined benefit pension plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Employees who were participating in El Paso's defined benefit pension plan on December 31, 1996 receive the greater of cash balance benefits or prior plan benefits accrued through December 31, 2001. Effective January 1, 2000, Sonat's pension plan was merged into our pension plan. Sonat employees who were participants in the Sonat pension plan on December 31, 1999 receive the greater of cash balance benefits or the Sonat plan benefits accrued through December 31, 2004.

Prior to our merger with Coastal, Coastal provided non-contributory pension plans covering substantially all of its U.S. employees. On April 1, 2001, Coastal's primary plan was merged into our existing plan. Coastal employees who were participants in Coastal's primary plan on March 31, 2001 receive the greater of cash balance benefits or the Coastal plan benefits accrued through March 31, 2006.

Following our mergers with Coastal and Sonat, we offered an early retirement incentive program for eligible employees of these organizations. These programs offered enhanced pension benefits to individuals who elected early retirement. Charges incurred in connection with the Sonat program were $8 million and those in connection with the Coastal program were $152 million.

Plan assets of Coastal's pension plan included Coastal's common stock and Class A common stock, amounting to a total of 8.9 million shares, after conversion, at December 31, 2000 and 1999. In addition to Coastal's primary pension plan, separate plans were provided to employees of our coal and convenience store operations. We also participate in several multi-employer pension plans for the benefit of our employees who are union members. Our contributions to these plans were not material for 2001 or 2000.

Retirement Savings Plan

We maintain a defined contribution plan covering all of our U.S. employees. We match 75 percent of participant basic contributions of up to 6 percent, with the matching contribution being made to the plan's stock fund. Participants can elect to move the matching contribution at any time into any of the seven remaining funds or leave them in the stock fund. Prior to our merger, Coastal matched 100 percent of basic contributions of up to 8 percent with matching contributions made in Coastal stock. Amounts expensed under these combined plans were approximately $30 million, $35 million and $36 million for the years ended December 31, 2001, 2000 and 1999.

Other Postretirement Benefits

We provide postretirement medical benefits for ANR Coal and closed groups of retired employees of EPNG, El Paso Tennessee, Sonat, and Coastal, and limited postretirement life insurance benefits for current and retired employees. Other postretirement employee benefits (OPEB) are prefunded to the extent such costs are recoverable through rates. To the extent actual OPEB costs for TGP, EPNG or SNG differ from the amounts recovered in rates, a regulatory asset or liability is recorded.

Under our early retirement incentive program for Coastal employees, participating eligible employees were allowed to keep postretirement medical and life benefits commencing at the later of age 50 or retirement. Total charges associated with the Coastal incentive program and the elimination of retiree benefits for future retirees were $65 million. Under our early retirement incentive program for employees of PG&E's Texas Midstream operations, participating eligible employees were allowed to keep postretirement medical and life benefits commencing at the later of age 55 or retirement. The total liabilities for this incentive program were $8 million.

Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs. We reserve the right to change these benefits.

The following table sets forth the change in benefit obligation, change in plan assets, reconciliation of funded status and components of net periodic benefit cost for pension benefits and other postretirement benefits. Our benefits are presented and computed as of and for the twelve months ended September 30. Coastal's 2000 and 2001 disclosure information was determined as of and for the twelve months ended December 31, 2000 and September 30, 2001.

	Pension Benefits		Postretirement Benefits	
	2001	2000	2001	2000
	(In millions)			
Change in benefit obligation				
Benefit obligation at beginning of period	$1,680	$1,636	$ 570	$ 597
Service cost	30	39	1	3
Interest cost	117	121	42	43
Participant contributions	—	—	17	12
Plan amendments	4	—	(12)	—
Settlements, curtailments and special termination benefits	137	—	17	—
Acquisition of PG&E's Texas Midstream operations	—	7	—	8
Actuarial (gain) or loss	135	16	(14)	(19)
Benefits paid	(137)	(139)	(61)	(74)
Benefit obligation at end of period	$1,966	$1,680	$ 560	$ 570
Change in plan assets				
Fair value of plan assets at beginning of period	$3,190	$2,820	$ 188	$ 155
Actual return on plan assets	(581)	482	(30)	12
Employer contributions	7	23	54	81
Participant contributions	—	—	17	10
Acquisition of PG&E's Texas Midstream operations	—	4	—	—
Benefits paid	(137)	(139)	(61)	(70)
Fair value of plan assets at end of period	$2,479	$3,190	$ 168	$ 188

	Pension Benefits		Postretirement Benefits	
	2001	2000	2001	2000
	(In millions)			
Reconciliation of funded status				
Funded status at end of period	$ 513	$1,510	$(392)	$(382)
Fourth quarter contributions and income	37	2	11	16
Unrecognized net actuarial loss (gain)	252	(760)	(15)	(55)
Unrecognized net transition obligation	(9)	(13)	31	110
Unrecognized prior service cost	(32)	(38)	(9)	(7)
Prepaid (accrued) benefit cost at December 31,	$ 761	$ 701	$(374)	$(318)

Included in the above information are plans in which the projected benefit obligation and accumulated benefit obligation for pension plans with accumulated benefit obligations in excess of plan assets were $51 million and $47 million as of December 31, 2001, and $50 million and $41 million as of December 31, 2000. Accrued benefit costs related to these plans for the years ended December 31, 2001 and 2000 were $61 million and $51 million.

The current liability portion of the postretirement benefits was $46 million as of December 31, 2001 and 2000. Benefit obligations are based upon actuarial estimates as described below. Where these assumptions differed, average rates have been presented.

	Pension Benefits			Postretirement Benefits		
	Year Ended December 31,					
	2001	2000	1999	2001	2000	1999
	(In millions)					
Benefit cost for the plans includes the following components						
Service cost	$ 35	$ 38	$ 42	$ 1	$ 3	$ 5
Interest cost	134	121	117	42	43	40
Expected return on plan assets	(311)	(277)	(250)	(10)	(8)	(9)
Amortization of net actuarial gain	(41)	(30)	(15)	(2)	(2)	(3)
Amortization of transition obligation	(6)	(6)	(6)	8	13	16
Amortization of prior service cost	(2)	(3)	(1)	(1)	—	(1)
Settlements, curtailment, and special termination benefits	137	—	1	65	—	29
Net benefit cost	$ (54)	$(157)	$(112)	$103	$49	$77

	Pension Benefits		Postretirement Benefits	
	2001	2000	2001	2000
Weighted average assumptions				
Discount rate	7.25%	7.75%	7.25%	7.75%
Expected return on plan assets	10.00%	10.00%	7.50%	6.96%
Rate of compensation increase	4.50%	4.44%	N/A	N/A

Actuarial estimates for our postretirement benefits plans assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 9.5 percent in 2001, gradually decreasing to 6 percent by the year 2008. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects:

	2001	2000
	(In millions)	
One Percentage Point Increase		
Aggregate of Service Cost and Interest Cost	$ 1	$ 1
Accumulated Postretirement Benefit Obligation	$ 22	$ 25
One Percentage Point Decrease		
Aggregate of Service Cost and Interest Cost	$ (1)	$ (1)
Accumulated Postretirement Benefit Obligation	$(21)	$(24)

16. Capital Stock

In December 2001, we issued 20.3 million shares of common stock for approximately $863 million (net of issuance costs).

We have 50,000,000 shares of authorized preferred stock, par value $0.01 per share, of which 7,500,000 shares have been designated as Series A Junior Participating Preferred Stock and reserved for issuance pursuant to our preferred stock purchase rights plan. In March 2000, we issued 200,000 shares of El Paso Series B Mandatorily Convertible Single Reset Preferred Stock in connection with the issuance of the Chaparral third party notes. In November 2001, we also issued 190,000 shares of El Paso Series C Mandatorily Convertible Single Reset Preferred Stock in connection with the issuance of the Gemstone third party notes. Each of the Chaparral and Gemstone preferred stock issuances were to separate share trusts that we own and, therefore, are not reflected as preferred stock issuances in our financial statements.

17. Stock-Based Compensation

We grant stock awards under various stock option plans. We account for our stock option plans using Accounting Principles Board Opinion No. 25 and its related interpretations. Under our employee plans, we may issue incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, stock appreciation rights (SARs), phantom stock options, and performance units. Under our non-employee director plans, we may issue non-qualified stock options and deferred shares of common stock. We have reserved approximately 74 million shares of common stock for existing and future stock awards. As of December 31, 2001, approximately 26 million shares remained unissued.

Non-qualified Stock Options

We granted non-qualified stock options to our employees in 2001, 2000, and 1999. Our stock options have contractual terms of 10 years and generally vest after completion of one to five years of continuous employment from the grant date. We also granted options to non-employee members of the Board of Directors at fair market value on the grant date that are exercisable immediately. A summary of our stock options and stock options outstanding as of December 31, 2001, 2000, and 1999 is presented below:

	Stock Options					
	2001		2000		1999	
	# Shares of Underlying Options	Weighted Average Exercise Prices	# Shares of Underlying Options	Weighted Average Exercise Prices	# Shares of Underlying Options	Weighted Average Exercise Prices
Outstanding at beginning of the year	19,664,151	$34.43	22,511,704	$32.80	15,331,658	$25.46
Granted	28,327,468	$60.19	1,065,110	$41.35	9,639,750	$41.02
Exercised	(1,396,409)	$25.88	(3,648,752)	$25.99	(2,092,953)	$18.26
Forfeited	(1,773,064)	$58.00	(263,911)	$38.44	(366,751)	$31.15
Outstanding at end of year	44,822,146	$50.02	19,664,151	$34.43	22,511,704	$32.80
Exercisable at end of year	14,357,245	$33.58	12,431,102	$30.51	12,996,454	$26.71

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/01	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 12/31/01	Weighted Average Exercise Price
$ 7.15 to $21.40	2,962,137	2.9	$16.56	2,962,137	$16.56
$21.41 to $42.90	14,216,949	7.0	$37.75	9,957,830	$36.46
$42.91 to $64.30	19,781,410	8.9	$55.69	1,398,861	$48.31
$64.31 to $71.50	7,861,650	9.1	$70.57	38,417	$65.17
$ 7.15 to $71.50	44,822,146	7.9	$50.02	14,357,245	$33.58

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

Assumption:	2001	2000	1999
Expected Term in Years	7.25	7.00	7.00
Expected Volatility	26.6%	23.9%	21.9%
Expected Dividends	3.0%	3.0%	3.0%
Risk-Free Interest Rate	4.7%	5.0%	6.3%

The Black-Scholes weighted average fair value of options granted during 2001, 2000 and 1999 was $15.75, $10.16, and $11.42.

Pro Forma Net Income and Net Income Per Common Share

Had the compensation expense for our stock-based compensation plans been determined applying the provisions of SFAS No. 123, our net income and net income per common share for 2001, 2000 and 1999 would approximate the pro forma amounts below:

	December 31, 2001		December 31, 2000		December 31, 1999	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
	(In millions, except per common share amounts)					
SFAS No. 123 charge, pretax	$ —	$ 360	$ —	$ 95	$ —	$ 160
APB No. 25 charge, pretax	$ 132	$ —	$ 38	$ —	$ 145	$ —
Net income (loss)	$ 93	$ (62)	$1,306	$1,268	$ 244	$ 232
Basic earnings (loss) per common share	$0.18	$(0.12)	$ 2.64	$ 2.57	$0.49	$0.47
Diluted earnings (loss) per common share	$0.18	$(0.12)	$ 2.57	$ 2.49	$0.49	$0.47

The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts. SFAS No. 123 does not apply to awards granted prior to the 1995 fiscal year.

Restricted Stock

Under our stock-based compensation plans, a limited number of shares of restricted common stock may be granted to our officers and employees. These shares carry voting and dividend rights; however, sale or transfer of the shares is restricted. These restricted stock awards vest over a specific period of time and/or if we achieve established performance targets. Restricted stock awards representing 2.3 million, 0.4 million, and 1.4 million shares were granted during 2001, 2000 and 1999 with a weighted average grant date fair value of $62.10, $34.82 and $35.10 per share. At December 31, 2001, 4.3 million shares of restricted stock were outstanding. The value of restricted shares subject to performance vesting is determined based on the fair market value on the date performance targets are achieved, and this value is charged to compensation expense ratably over the required service or restriction period. The value of time vested restricted shares is determined at their issuance date and this cost is amortized to compensation expense over the period of service. For 2001, 2000, and 1999, these charges totaled $144 million, $13 million, and $69 million. Included in deferred compensation at December 31, 2000, is $69 million related to options that will be converted automatically into common stock at the end of their vesting period. These options met all performance targets in December 2000.

Performance Units and Phantom Stock Options

We award eligible employees phantom stock options that are payable in cash. We also award eligible employees and officers performance units that are payable in cash or stock at the end of the vesting period. The final value of the performance units may vary according to the plan under which they are granted, but is usually based on our common stock price at the end of the vesting period or total shareholder return during the vesting period. The value of the performance units is charged ratably to compensation expense over the vesting period with periodic adjustments to account for the fluctuation in the market price of our stock or changes in expected total shareholder return. Amounts charged to compensation expense in 2001, 2000 and 1999 were $64 million, $25 million and $30 million. Our 2001 expense includes a $51 million charge to pay out all of our outstanding phantom stock options. Included in the 1999 amount is $22 million related to the accelerated vesting of the performance units due to the change in control resulting from the merger with Sonat.

Employee Stock Purchase Program

In October 1999, we implemented an employee stock purchase plan under Section 423 of the Internal Revenue Code. The plan allows participating employees the right to purchase common stock on a quarterly basis at 85 percent of the lower of the market price at the beginning of the plan period or at the end of each calendar quarter. Two million shares of common stock are authorized for issuance under this plan.

The following table presents the number of shares issued and the price per share by quarter for the year ended December 31:

	2001		2000		1999	
	Shares	Price per Share	Shares	Price per Share	Shares	Price per Share
1st Quarter	75,851	$55.10	90,718	$32.33	—	$ —
2nd Quarter	90,319	$44.22	87,622	$32.33	—	$ —
3rd Quarter	104,404	$34.58	84,780	$32.33	—	$ —
4th Quarter	42,570(1)	$38.34	83,212	$32.33	139,842	$33.10
Total	313,144		346,332		139,842	

(1) Since many employees reached the maximum contribution that is imposed by Section 423 of the Internal Revenue Code in the third quarter of 2001, they were excluded from participating in the fourth quarter of 2001.

Funds we receive under this program may be used for general corporate purposes. However, we record a liability for the withholdings not yet applied towards the purchase of common stock. We bear all expenses associated with administering the plan, except for costs, including any applicable taxes, associated with the participants' sale of common stock.

18. Segment Information

Our business activities are segregated into four segments: Pipelines, Merchant Energy, Production, and Field Services. These segments are strategic business units that offer a variety of different energy products and services. We manage each segment separately as each business requires different technology and marketing strategies.

Our Pipelines segment provides natural gas transmission services in the U.S. and internationally. We conduct our activities through seven wholly owned and eight partially owned interstate transmission systems along with six underground natural gas storage facilities and a LNG terminalling facility. Our pipeline operations also include access between our U.S. based systems and Canada and Mexico as well as interests in three operating natural gas transmission systems in Australia.

Our Merchant Energy segment is involved in a broad range of energy-related activities, including asset ownership, customer origination, marketing and trading and financial services. We buy, sell and trade natural gas, power, crude oil, refined products, coal and other energy commodities throughout the world, and own or have interests in 95 power generation plants in 20 countries.

Our Production segment is engaged in the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. Production has onshore and coal seam operations and properties in 19 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey.

Our Field Services segment provides wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and natural gas liquids. Field Services' assets are located in the San Juan Basin, the Rocky Mountains, east and south Texas, the Mid-Continent, Permian Basin, the Gulf of Mexico and Louisiana.

The accounting policies of the individual segments are the same as those described in Note 1. Since earnings on equity investments can be a significant component of earnings in several of our segments, we have chosen to evaluate segment performance based on earnings before interest and taxes (EBIT) instead of operating income. To the extent practicable, results of operations for the years ended December 31, 2000 and 1999 have been reclassified to conform to the current business segment presentation, although such results are not necessarily indicative of the results which would have been achieved had the revised business segment structure been in effect during that period.

	Segments As of or for the Year Ended December 31, 2001					
	Pipelines	Merchant Energy	Production	Field Services	Other[1]	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,451	$51,025	$ 199	$1,809	$ 379	$55,863
Foreign	2	1,560	46	4	—	1,612
Intersegment revenue[2]	295	486	2,102	740	(3,623)	—
Merger-related costs and asset impairment charges	316	243	63	46	1,175	1,843
Ceiling test charges	—	—	135	—	—	135
Depreciation, depletion, and amortization	383	139	678	111	48	1,359
Operating income (loss)	882	378	919	124	(1,470)	833
Other income	156	519	1	71	41	788
EBIT	1,038	897	920	195	(1,429)	1,621
Extraordinary items, net of income taxes	(27)	(7)	—	(5)	65	26
Assets						
Domestic	14,345	11,021	7,584	3,564	3,952	40,466
Foreign	98	6,684	874	17	32	7,705
Capital expenditures and investments in unconsolidated affiliates	1,093	1,154	2,521	165	832	5,765
Total investments in unconsolidated affiliates	1,104	3,543	77	554	19	5,297

(1) Includes Corporate and Other and eliminations as well as retail operations through June 2001 and telecommunications operations which has not had significant activity. We sold a majority of our retail operations in 2001.

(2) The increase in intersegment revenue from 2000 to 2001 for our Production segment is primarily due to the consolidation of Engage in September 2000.

	Segments As of or for the Year Ended December 31, 2000					
	Pipelines	Merchant Energy	Production	Field Services	Other[(1)]	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,521	$38,327	$1,134	$1,307	$ 1,193	$44,482
Foreign	—	4,426	5	2	—	4,433
Intersegment revenue	220	353	547	130	(1,250)	—
Merger-related costs and asset impairment charges	—	21	—	11	93	125
Depreciation, depletion, and amortization	376	116	611	76	68	1,247
Operating income (loss)	1,142	552	613	162	(85)	2,384
Other income (loss)	181	377	(4)	52	28	634
EBIT	1,323	929	609	214	(57)	3,018
Extraordinary items, net of income taxes	89	—	—	(19)	—	70
Assets						
Domestic	14,025	15,058	5,856	3,752	3,256	41,947
Foreign	83	4,018	198	17	57	4,373
Capital expenditures and investments in unconsolidated affiliates	725	1,170	2,067	484	1,082	5,528
Total investments in unconsolidated affiliates	1,119	2,643	7	567	74	4,410

(1) Includes Corporate and Other and eliminations as well as retail operations and telecommunications operations which has not had significant activity.

	Segments As of or for the Year Ended December 31, 1999					
	Pipelines	Merchant Energy	Production	Field Services	Other[(1)]	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,638	$19,708	$ 704	$ 664	$ 1,059	$24,773
Foreign	—	2,544	8	—	—	2,552
Intersegment revenue	118	395	396	103	(1,012)	—
Merger-related costs and asset impairment charges	90	67	31	8	361	557
Ceiling test charges	—	—	352	—	—	352
Depreciation, depletion, and amortization	408	131	449	67	46	1,101
Operating income (loss)	1,053	2	(86)	70	(329)	710
Other income	147	259	1	60	42	509
EBIT	1,200	261	(85)	130	(287)	1,219
Cumulative effect of accounting change, net of income taxes	—	(13)	—	—	—	(13)
Assets						
Domestic	14,035	5,559	4,352	1,842	2,712	28,500
Foreign	53	3,391	74	—	72	3,590
Capital expenditures and investments in unconsolidated affiliates	685	1,590	1,447	198	71	3,991
Total investments in unconsolidated affiliates	1,220	1,937	6	438	11	3,612

(1) Includes Corporate and Other and eliminations as well as retail operations.

The reconciliations of EBIT to income before extraordinary items and the cumulative effect of accounting change are presented below for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
Total EBIT for segments	$1,621	$3,018	$1,219
Interest and debt expense	1,155	1,040	776
Minority interest	217	204	93
Income tax expense	182	538	93
Income before extraordinary items and cumulative effect of accounting change	$ 67	$1,236	$ 257

We had no customers whose revenues exceeded 10 percent of our total revenues in 2001, 2000 and 1999.

19. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for the years ended December 31:

	2001	2000	1999
		(In millions)	
Interest paid	$1,402	$ 967	$ 728
Income tax payments	62	112	19

See Note 2 for a discussion of the non-cash investing transactions related to our acquisitions.

20. Investments in and Advances to Unconsolidated Affiliates

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines, power generation plants, and gathering systems. Our investment balance includes unamortized purchase price differences of $393 million and $402 million as of December 31, 2001 and 2000 that are being amortized over the remaining life of the unconsolidated affiliate's underlying assets. Our net ownership interest, investments in and advances to our unconsolidated affiliates are as follows as of December 31:

	Net Ownership Interest	Investments		Advances	
		2001	2000	2001	2000
			(In millions)		
Alliance Pipeline Limited Partnership	14%	$ 160	$ 216	$ —	$ —
Aux Sable Liquid	14%	58	56	—	—
Bastrop Company, LLC	50%	99	33	—	—
CE Generation	50%	360	354	—	—
Chaparral Investors (Electron) [1]	20%	341	268	895	—
Citrus Corporation[2]	50%	512	474	—	—
Eagle Point Cogeneration Partnership	84%	85	34	—	—
El Paso Energy Partners	27%[3]	380	368	—	—
Great Lakes Gas Transmission, LP	50%	297	291	—	—
Javelina Company	40%	48	55	—	—
Midland Cogeneration Venture	44%	276	198	—	—
Other Domestic Investments[4]	various	533	529	40	106
Domestic		$3,149	$2,876	$ 935	$106

	Country	Net Ownership Interest	Investments		Advances	
			2001	2000	2001	2000
			(In millions)			
CAPSA/CAPEX	Argentina	45%	$ 259	$ 282	$ —	$ —
Gasoducto del Pacifico Pipeline (Argentina to Chile)	Argentina/Chile	16%	71	70	—	—
Bolivia to Brazil Pipeline	Bolivia/Brazil	8%	50	53	—	—
Porto Velho (Gemstone)[5]	Brazil	—	—	99	—	—
Diamond Power (Gemstone)[5]	Brazil	50%	555	—	—	—
Pescada	Brazil	50%	70	—	—	—
Meizhou Wan Generating	China	25%	76	7	—	—
Empresa Generadora de Electridad (Itabo)	Dominican Republic	25%	101	99	—	—
Enfield Power	United Kingdom	25%	53	40	—	—
Korea Independent Energy Corporation	Korea	50%	104	108	—	—
Samalayuca Power	Mexico	50%	103	93	—	—
Habibullah Power	Pakistan	50%	53	53	—	—
EGE Fortuna	Panama	24%	56	53	—	—
Aguaytia Energy	Peru	24%	52	26	—	—
East Asia Power	Philippines	—	—	51	—	67
Other Foreign Investments[4]	various	various	545	500	68	116
Foreign			$2,148	$1,534	$ 68	$183
Total investments in and advances to unconsolidated affiliates			$5,297	$4,410	$1,003	$289

(1) Mesquite Investors, LLC is included in Chaparral.
(2) Citrus corporation owns 100 percent of Florida Gas Transmission System.
(3) Our ownership interest consists of a one percent general partner interest, 26 percent of the partnership's common units and preferred units with $143 million liquidation value.
(4) Denotes investments less than $50 million.
(5) Contributed to Gemstone in 2001.

Earnings from our unconsolidated affiliates are as follows for each of the three years ended December 31:

	2001	2000	1999
		(In millions)	
Alliance Pipeline Limited Partnership	$ 23	$ 12	$ 10
Bolivia to Brazil Pipeline	1	—	4
CAPSA/CAPEX	(12)	4	3
CE Generation	29	35	24
Chaparral Investors (Electron)	75	(5)	(8)
Citrus Corporation	41	51	25
Diamond Power (Gemstone)	2	—	—
Eagle Point Cogeneration Partnership	22	25	22
East Asia Power	(4)	(32)	—
Empire State Pipeline	3	8	9
El Paso Energy Partners	47	20	18
Engage Energy US, LP and Engage Energy Canada, LP (through September 2000)	—	11	5
Great Lakes Gas Transmission, LP	55	52	52
Iroquois Gas Pipeline System, LP	3	7	6
Javelina Company	(1)	17	10
Korea Independent Energy Corporation	20	—	—
Midland Cogeneration Venture	23	37	16
Porto Velho (Gemstone)	(6)	1	—
Samalayuca Power	12	17	17
Other	163	132	72
Total earnings from our unconsolidated affiliates	$496	$392	$285

As discussed in Note 2, we have divested our ownership interest in the Empire State, Iroquois, Stingray, and U-T offshore pipeline systems.

In October 2000, we terminated the Engage joint venture that was formed in 1997. As a result, the operations were divided into separate entities that are owned and operated independently by each former joint venture partner.

Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $38 million and $48 million for December 31, 2001 and 2000 and total assets of $766 million and $589 million for December 31, 2001 and 2000.

	Year Ended December 31,		
	2001	2000	1999
		(Unaudited) (In millions)	
Operating results data:			
Revenues and other income	$2,515	$4,947	$4,275
Costs and expenses	2,011	4,411	3,921
Income from continuing operations	504	536	354
Net income	496	368	291

	December 31, 2001	December 31, 2000
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$ 1,320	$ 1,781
Non-current assets	10,823	11,100
Short-term debt	412	518
Other current liabilities	938	1,047
Long-term debt	4,452	4,330
Other non-current liabilities	1,706	3,045
Minority interest	32	36
Equity in net assets	4,603	3,905

The following table shows revenues and charges from our unconsolidated affiliates:

	2001	2000	1999
		(In millions)	
Revenues[1]	$379	$1,289	$545
Cost of sales[1]	347	381	170
Management fee income	150	82	20
Reimbursement for costs	61	46	21
Interest income	45	23	14
Interest expense	50	49	2

(1) The decrease in 2001 affiliated revenue and cost of sales is due primarily to the consolidation of Engage in September 2000.

Chaparral

During 1999, we formed a series of companies with a third-party financial investor that we refer to as Chaparral. Chaparral (also known as Electron) was formed to obtain low cost financing to fund the growth of our unregulated domestic power generation and related businesses. Chaparral has acquired and currently owns equity interests in 39 natural gas-fired generation facilities in Arizona, California, Colorado, Connecticut, Florida, Massachusetts, Nevada, New Jersey, New York, Pennsylvania and Rhode Island. Chaparral also owns several operating companies that provide the services required to operate and maintain these facilities and a natural gas service company that provides fuel procurement services to eight of Chaparral's natural gas-fired generation facilities in California.

Total third party capital in Chaparral was $1.15 billion, including $0.12 billion contributed in 1999 and $1.03 billion contributed in 2000, of which $1.0 billion was debt raised in 2000 by the third party investor through a note issuance that matures in March 2003.

We have entered into various financing transactions with Chaparral and its subsidiaries each year, which include capital contributions, debt issuances and advances.

The following table summarizes the presentation of these transactions on our balance sheet at December 31 (in millions):

	2001	2000
Debt securities payable	$(169)	$(253)
Notes receivable (payable)	343	(241)
Credit facility receivable	552	—
Contingent interest promissory notes payable	(289)	(174)
Net	437	(668)
Equity investment	341	268
Net investment	$ 778	$(400)

We account for our equity investment in Chaparral using the equity method of accounting since we do not have the ability to exercise control over the entity. The debt securities, notes payable and receivable, revolving credit facility, and contingent interest promissory notes are included in current and long-term receivables and payables from unconsolidated affiliates, as appropriate, with the related interest as interest income or expense in our income statement.

The debt securities payable to Chaparral are payable on demand and carry a fixed interest rate of 7.443%. The notes payable and receivable from Chaparral are payable on demand and carry various fixed interest rates. The credit facility was established in 1999 and allows Chaparral to borrow up to $725 million from us at a variable interest rate, which was 2.6% at December 31, 2001.

The contingent interest promissory notes carry a variable interest rate not to exceed 12.75% and mature in 2019 through 2021. The interest payments are contingent on cash flow distributions from five power plant investments we own, with the principal repayment being guaranteed by us. If we sell these investments, the maturity date of the notes may be accelerated.

Chaparral has used our funds and the funds raised from the third-party financial investors to acquire the domestic power generation and related businesses described above. In some cases, Chaparral acquired these power generation assets from us. Chaparral acquired power generation assets from us with a value of $276 million and $659 million in 2001 and 2000, which we determined to be a fair and reasonable amount. We did not recognize any gains or losses on those transactions.

In addition to the financing transactions described above, we have also entered into various contractual agreements with Chaparral related to management and trading activities.

We serve as manager of Chaparral under a management agreement that expires in 2006. We are compensated for the services we provide through an annual performance-based management fee, which amounted to $147 million in 2001 and $80 million in 2000. This performance-based management fee is calculated based on the value of Chaparral's assets as determined using cash flow techniques. We also receive a fixed fee reimbursement for out-of-pocket and third-party expenses we incurred on behalf of Chaparral, which was $20 million for 2001 and 2000.

Our Merchant Energy segment also enters into various contractual agreements with Chaparral and its operating subsidiaries in conjunction with Chaparral's operations. These include agreements to (i) supply natural gas or other fuels to power Chaparral's facilities; (ii) purchase all or a portion of the power produced by Chaparral's facilities; (iii) provide some or all of the power supply that Chaparral is obligated to provide to fulfill agreements it has with third parties; (iv) purchase tolling rights; and (v) provide other services to Chaparral related to its operations. We account for these agreements as trading price risk management activities and recognized revenues of $266 million and $119 million in 2001 and 2000 and costs of sales of $121 million and $42 million in 2001 and 2000 related to these transactions.

As additional credit support for Chaparral's notes, we issued mandatorily convertible preferred stock with an aggregate liquidation preference of $1 billion to a share trust we control. Upon the occurrence of negative events, including a decline in our stock price below $27.07 for ten consecutive trading days coupled with downgrades in our credit ratings to below investment grade, we could be required to remarket our preferred stock on terms that are designed to generate a sufficient amount of cash to repay the third party investor's debt.

Gemstone

In November 2001, we formed with a third-party financial investor a series of companies that we refer to as Gemstone. Gemstone was formed to provide a financing vehicle through which we fund the development and growth of our power generation, merchant energy, and related businesses in Brazil.

The third party financial investor contributed into Gemstone $50 million in capital and raised an additional $950 million through a note issuance that matures in October 2004. The proceeds were used by Gemstone to acquire a Brazilian power investment, invest $300 million in preferred securities of one of our consolidated subsidiaries and temporarily invest excess proceeds of $462 million in short-term notes from us. Our debt securities had an outstanding balance of $346 million at December 31, 2001, are payable on demand

and carry a fixed interest rate of 5.25%. The preferred securities of our subsidiary entitle Gemstone to a preferred return of 8.03%.

We contributed $280 million in cash as well as several Brazilian investments with a total value of $274 million in exchange for our interest in Gemstone. Through Gemstone, we received approximately $762 million in cash through the issuance of our debt securities and preferred securities to Gemstone from which were used to acquire an interest in electric generation assets in Brazil and for general corporate purposes.

Our investment in Gemstone as of December 31, 2001, is $555 million, and we account for our investment using the equity method of accounting since we do not have the ability to exercise control over the entity. The short-term notes we issued are included in short-term borrowings in our balance sheet, with the related interest as interest expense in our income statement. We account for the investor's preferred interest in our consolidated subsidiary as a minority interest in our balance sheet and the preferred return as minority interest expense in our income statement.

Under our management agreement with Gemstone, we earn a cost-based management fee. This fee was not significant in 2001. We have also entered into a participation agreement with one of Gemstone's power generation interests whereby we earn a fee for managing, constructing, and operating the related facilities and marketing and distributing the energy produced by these facilities. This fee was not significant in 2001.

As additional credit support for Gemstone's notes, we issued mandatorily convertible preferred stock with an aggregate liquidation preference of $950 million to a share trust we control. Upon the occurrence of negative events, including a decline in our stock price below $36.16 for ten consecutive trading days coupled with downgrades in our credit ratings to below investment grade, we could be required to remarket our preferred stock on terms that are designed to generate a sufficient amount of cash to repay the third party investor's debt.

Photon

During 2000, we contributed $44 million of equity capital and assets to a series of companies we refer to as Photon. Photon acquired and held telecommunications assets. A third party financial investor contributed $60 million to Photon and earned a preferred return. We had a subordinated promissory note receivable from Photon and a demand note payable to Photon with a net receivable balance of approximately $33 million at December 31, 2000 that was paid in 2001.

During 2001, we acquired the third-party interest for a fair value of $63 million. We accounted for this acquisition as a purchase reflecting the carrying amount of Photon's assets and liabilities in our consolidated financial statements.

El Paso Energy Partners

During the third quarter of 2000, El Paso Energy Partners completed a public offering of 4.6 million common units. The offering reduced our common units ownership interest from 32.5 percent to 27.8 percent. This transaction had no effect on our general partner interest or our non-managing member interest. Also, in the third quarter, we received $170 million of Series B preference units in exchange for the sale of the natural gas storage businesses of Crystal Gas Storage, Inc., our wholly owned subsidiary, to El Paso Energy Partners. These preference units accrue dividends at a rate of 10% on a cumulative basis, and are redeemable at the option of El Paso Energy Partners.

In 2001, as a result of our merger with Coastal, El Paso Energy Partners sold its interest in several offshore assets including seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Proceeds from these sales were approximately $135 million and resulted in a loss to the partnership of approximately $25 million. As consideration for these sales, we committed to pay El Paso Energy Partners a series of payments totaling $29 million, and were required to contribute $40 million to a trust related to one of the assets sold by El Paso Energy Partners. These payments have been recorded as merger-related costs.

In March 2001, El Paso Energy Partners issued 2.3 million common units reducing our ownership interest in the common units to 26 percent. In October 2001, the partnership issued 5.6 million common units, of which we purchased 1.5 million units maintaining our common unit ownership interest at 26 percent. Also, in October 2001, the partnership redeemed $50 million liquidation value of the Series B preference units we received in the Crystal transaction. At December 31, 2001, the liquidation value of the remaining Series B preference units was $143 million.

As the general partner, we perform substantially all of the daily operations and provide strategic direction for El Paso Energy Partners. We have a management agreement and other operating agreements with El Paso Energy Partners that provide for the reimbursement of various operational, financial, accounting and administrative services that we perform for the partnership. The management agreement expires on June 30, 2002, and may be terminated thereafter upon a 90-day notice by either party. We recorded total reimbursements of $34 million and $22 million in 2001 and 2000.

In addition to the activities described above, we enter into transactions with El Paso Energy Partners in the normal course of business for the sale of natural gas and for services such as transportation and fractionation, storage, processing and other types of operational services. These activities are based on the same terms as our non-affiliates. We recognized revenues of $34 million and $17 million in 2001 and 2000 and cost of sales of $56 million and $26 million in 2001 and 2000.

21. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below:

	Quarters Ended			
	December 31	September 30	June 30	March 31
	(In millions, except per common share amounts)			
2001				
Operating revenues[1]	$12,115	$13,859	$13,739	$17,762
Merger-related costs and asset impairment charges	49	32	601	1,161
Ceiling test charges	—	135	—	—
Operating income (loss)[1]	612	480	(47)	(212)
Income (loss) before extraordinary items	375	216	(134)	(390)
Extraordinary items, net of income taxes	—	(5)	41	(10)
Net income (loss)	375	211	(93)	(400)
Basic earnings (loss) per common share				
Income (loss) before extraordinary items	$ 0.74	$ 0.43	$ (0.26)	$ (0.78)
Extraordinary items, net of income taxes	—	(0.01)	0.08	(0.02)
Net income (loss)	$ 0.74	$ 0.42	$ (0.18)	$ (0.80)
Diluted earnings (loss) per common share				
Income (loss) before extraordinary items	$ 0.72	$ 0.42	$ (0.26)	$ (0.78)
Extraordinary items, net of income taxes	—	(0.01)	0.08	(0.02)
Net income (loss)	$ 0.72	$ 0.41	$ (0.18)	$ (0.80)

(1) Adjustments were made to conform the accounting presentation of Coastal to our presentation and include reclassifications to conform to our current presentation. These reclassifications had no impact on our net income or retained earnings.

	Quarters Ended			
	December 31	September 30	June 30	March 31
	(In millions, except per common share amounts)			
2000				
Operating revenues[1]	$16,299	$13,483	$10,380	$8,753
Merger-related costs and asset impairment charges	69	3	49	4
Operating income[1]	681	568	540	595
Income before extraordinary items	354	282	261	339
Extraordinary items, net of income taxes	(19)	—	—	89
Net income	335	282	261	428
Basic earnings (loss) per common share				
Income before extraordinary items	$ 0.71	$ 0.57	$ 0.53	$ 0.69
Extraordinary items, net of income taxes	(0.04)	—	—	0.18
Net income	$ 0.67	$ 0.57	$ 0.53	$ 0.87
Diluted earnings (loss) per common share				
Income before extraordinary items	$ 0.69	$ 0.55	$ 0.52	$ 0.67
Extraordinary items, net of income taxes	(0.04)	—	—	0.18
Net income	$ 0.65	$ 0.55	$ 0.52	$ 0.85

(1) Adjustments were made to conform the accounting presentation of Coastal to our presentation and include reclassifications to conform to our current presentation. These reclassifications had no impact on our net income or retained earnings.

22. Supplemental Natural Gas and Oil Operations (Unaudited)

At December 31, 2001, we had interests in natural gas and oil properties in 19 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have a limited number of natural gas and oil properties in Brazil, Canada and Indonesia as well as exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey.

For purposes of the Supplemental Natural Gas and Oil Operations disclosure, we have presented reserves, standardized measure of discounted future net cash flows and the related changes in standardized measure separately for natural gas systems operations which includes the regulated natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries. The Supplemental Natural Gas and Oil Operations disclosure does not include any value for natural gas systems storage gas and liquids volumes managed by our pipeline segment.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31 (in millions):

	United States	Canada	Other Countries[(1)]	Worldwide
2001				
Natural gas and oil properties:				
Costs subject to amortization	$12,933	$415	$ 72	$13,420
Costs not subject to amortization	629	250	49	928
	13,562	665	121	14,348
Less accumulated DD&A	6,956	170	31	7,157
Net capitalized costs	$ 6,606	$495	$ 90	$ 7,191
2000				
Natural gas and oil properties:				
Costs subject to amortization	$ 9,963	$114	$ —	$10,077
Costs not subject to amortization	802	32	12	846
	10,765	146	12	10,923
Less accumulated DD&A	5,397	1	—	5,398
Net capitalized costs	$ 5,368	$145	$ 12	$ 5,525

(1) Includes international operations in Brazil and Indonesia.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31 (in millions):

	United States	Canada	Other Countries[(1)]	Worldwide
2001				
Property acquisition costs				
Proved properties	$ 91	$232	$—	$ 323
Unproved properties	44	16	25	85
Exploration costs	177	19	58	254
Development costs	1,529	105	14	1,648
Total costs incurred	$1,841	$372	$97	$2,310
2000				
Property acquisition costs				
Proved properties	$ 201	$ 3	$—	$ 204
Unproved properties	171	6	—	177
Exploration costs	290	42	11	347
Development costs	1,229	69	—	1,298
Total costs incurred	$1,891	$120	$11	$2,026
1999				
Property acquisition costs				
Proved properties	$ 157	$ —	$—	$ 157
Unproved properties	187	10	—	197
Exploration costs	289	11	—	300
Development costs	766	5	—	771
Total costs incurred	$1,399	$ 26	$—	$1,425

(1) Includes international operations in Brazil and Indonesia.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditure that are not being amortized as of December 31, 2001, pending determination of proved reserves.

Capitalized interest of $51 million, $25 million, and $2 million for the years ended December 31, 2001, 2000 and 1999 is included in the presentation below (in millions):

	Cumulative Balance December 31,	Costs Excluded for Years Ended December 31,			Cumulative Balance December 31,
	2001	2001	2000	1999	1998
Worldwide					
Acquisition	$672	$346	$154	$ 80	$ 92
Exploration	139	57	53	21	8
Development	117	41	35	23	18
	$928	$444	$242	$124	$118

Projects presently excluded from amortization are in various stages of evaluation. The majority of these costs are expected to be included in the amortization calculation in the years 2002 through 2005. Total amortization expense per Mcfe, including ceiling test charges, was $1.22, $1.00, and $1.64 in 2001, 2000, and 1999. Excluding ceiling test charges, amortization expense would have been $1.04 and $0.91 per Mcfe in 2001 and 1999. Depreciation, depletion, and amortization excludes provisions for the impairment of international projects of $15 million in 2000 and $10 million in 1999.

All of our proved properties, with the exception of the proved reserves in Brazil and Indonesia, are located in North America (U.S. and Canada).

Net quantities of proved developed and undeveloped reserves of natural gas and liquids, including condensate and crude oil, and changes in these reserves are presented below. These reserves include 124,158, 197,782 and 259,342 MMcfe of production delivery commitments under financing arrangements that extend through 2005. Total proved reserves on the fields with this dedicated production were 1,981,239 MMcfe. In addition, this table excludes Production's 50 percent interest in UnoPaso (Pescada in Brazil), Merchant Energy's 50 percent equity interest in Sengkang in Indonesia, Merchant Energy's 45 percent and 24.75 percent equity interest in CAPSA and CAPEX in Argentina, and Field Services' 27 percent equity interest in El Paso Energy Partners. Combined proved reserve balances for these equity interests include natural gas reserves of 361,997 MMcf and liquids reserves of 44,711 MBbls, both net of our ownership interests.

	Natural Gas (in Bcf)				
	United States	Canada	Other Countries[(1)]	Worldwide	Natural Gas Systems[(2)]
Net proved developed and undeveloped reserves[(3)]					
January 1, 1999	3,738	—	—	3,738	212
Revisions of previous estimates	(126)	—	—	(126)	22
Extensions, discoveries and other	934	73	—	1,007	—
Purchases of reserves in place	573	—	—	573	—
Sales of reserves in place	(163)	—	—	(163)	—
Production	(416)	—	—	(416)	(36)
December 31, 1999	4,540	73	—	4,613	198
Revisions of previous estimates	(249)	(62)	—	(311)	11
Extensions, discoveries and other	1,239	155	91	1,485	—
Purchases of reserves in place	577	2	—	579	—
Sales of reserves in place	(19)	—	—	(19)	—
Production	(516)	(1)	—	(517)	(33)
December 31, 2000	5,572	167	91	5,830	176
Revisions of previous estimates	(874)	(136)	(51)	(1,061)	42
Extensions, discoveries and other	1,244	85	—	1,329	—
Purchases of reserves in place	116	83	—	199	—
Sales of reserves in place	(46)	—	—	(46)	—
Production	(552)	(13)	—	(565)	(35)
December 31, 2001	5,460	186	40	5,686	183
Proved developed reserves					
December 31, 1999	2,593	27	—	2,620	198
December 31, 2000	2,877	112	—	2,989	176
December 31, 2001	2,967	138	—	3,105	183

(1) Includes international operations in Brazil and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

(3) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

	Liquids[1] (in MBbls)				
	United States	Canada	Other Countries[2]	Worldwide	Natural Gas Systems[3]
Net proved developed and undeveloped reserves[4]					
January 1, 1999	81,764	—	—	81,764	237
Revisions of previous estimates	(6,956)	—	—	(6,956)	36
Extensions, discoveries and other	15,953	867	—	16,820	—
Purchases of reserves in place	11,494	—	—	11,494	—
Sales of reserves in place	(4,639)	—	—	(4,639)	—
Production	(10,300)	—	—	(10,300)	(24)
December 31, 1999	87,316	867	—	88,183	249
Revisions of previous estimates	(576)	(544)	—	(1,120)	7
Extensions, discoveries and other	13,196	3,600	4,862	21,658	—
Purchases of reserves in place	7,589	13	—	7,602	—
Sales of reserves in place	(609)	—	—	(609)	—
Production	(11,614)	(13)	—	(11,627)	(25)
December 31, 2000	95,302	3,923	4,862	104,087	231
Revisions of previous estimates	26,085	(4,224)	(4,862)	16,999	(118)
Extensions, discoveries and other	38,536	1,173	7,771	47,480	—
Purchases of reserves in place	132	10,570	—	10,702	—
Sales of reserves in place	(71)	—	—	(71)	—
Production	(13,821)	(560)	—	(14,381)	(16)
December 31, 2001	146,163	10,882	7,771	164,816	97
Proved developed reserves					
December 31, 1999	53,403	312	—	53,715	249
December 31, 2000	55,044	2,723	—	57,767	231
December 31, 2001	92,060	7,341	—	99,401	97

(1) Includes oil, condensate, and natural gas liquids.

(2) Includes international operations in Brazil and Indonesia.

(3) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

(4) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner.

The significant changes to reserves, other than purchases, sales or production, are due to reservoir performance in existing fields and from drilling additional wells in existing fields. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2001.

Results of operations from producing activities by fiscal year were as follows at December 31 (in millions):

	United States	Canada	Other Countries[1]	Worldwide
2001				
Net Revenues				
Sales to external customers	$ 139	$ 45	$ —	$ 184
Affiliated sales	2,259	1	—	2,260
Total	2,398	46	—	2,444
Production costs	(323)	(12)	—	(335)
Depreciation, depletion and amortization	(660)	(17)	—	(677)
Ceiling test charges	—	(87)	(28)	(115)
	1,415	(70)	(28)	1,317
Income tax (expense) benefit	(490)	25	(9)	(474)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 925	$ (45)	$ (37)	$ 843
2000				
Net Revenues				
Sales to external customers	$ 1,165	$ 6	$ —	$ 1,171
Affiliated sales	438	—	—	438
Total	1,603	6	—	1,609
Production costs	(310)	(1)	—	(311)
Depreciation, depletion and amortization	(584)	(1)	—	(585)
	709	4	—	713
Income tax (expense) benefit	(237)	(2)	—	(239)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 472	$ 2	$ —	$ 474
1999				
Net Revenues				
Sales to external customers	$ 559	$ —	$ —	$ 559
Affiliated sales	478	—	—	478
Total	1,037	—	—	1,037
Production costs	(252)	—	—	(252)
Depreciation, depletion and amortization	(433)	—	—	(433)
Ceiling test charges	(352)	—	—	(352)
	—	—	—	—
Income tax (expense) benefit	12	—	—	12
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 12	$ —	$ —	$ 12

[1] Includes international operations in Brazil and Indonesia.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows at December 31 (in millions):

	United States	Canada	Other Countries[(1)]	Worldwide	Natural Gas Systems[(2)]
2001					
Future cash inflows	$ 16,805	$ 641	$ 253	$ 17,699	$ 313
Future production and development costs	(5,351)	(279)	(124)	(5,754)	(64)
Future income tax expenses	(2,568)	(8)	(23)	(2,599)	(83)
Future net cash flows	8,886	354	106	9,346	166
10% annual discount for estimated timing of cash flows	(3,517)	(143)	(52)	(3,712)	(72)
Standardized measure of discounted future net cash flows	$ 5,369	$ 211	$ 54	$ 5,634	$ 94
2000					
Future cash inflows	$ 44,459	$1,597	$ 397	$ 46,453	$ 474
Future production and development costs	(7,194)	(171)	(209)	(7,574)	(110)
Future income tax expenses	(11,885)	(599)	(60)	(12,544)	(116)
Future net cash flows	25,380	827	128	26,335	248
10% annual discount for estimated timing of cash flows	(10,392)	(469)	(109)	(10,970)	(89)
Standardized measure of discounted future net cash flows	$ 14,988	$ 358	$ 19	$ 15,365	$ 159
1999					
Future cash inflows	$ 11,671	$ —	$ —	$ 11,671	$ 229
Future production and development costs	(3,730)	—	—	(3,730)	(74)
Future income tax expenses	(1,723)	—	—	(1,723)	(49)
Future net cash flows	6,218	—	—	6,218	106
10% annual discount for estimated timing of cash flows	(2,212)	—	—	(2,212)	(41)
Standardized measure of discounted future net cash flows	$ 4,006	$ —	$ —	$ 4,006	$ 65

(1) Includes international operations in Brazil and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end market natural gas and oil prices. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions and corporate investment criteria.

The following are the principal sources of change in the standardized measure of discounted future net cash flows (in millions):

	Years Ended December 31,					
	2001		2000		1999	
	Exploration and Production[1]	Natural Gas Systems[2]	Exploration and Production	Natural Gas Systems	Exploration and Production	Natural Gas Systems
Sales and transfers of natural gas and oil produced net of production costs	$ (2,108)	$ (255)	$(1,748)	$ (52)	$ (849)	$ (36)
Net changes in prices and production costs	(14,849)	10	12,095	150	1,034	(6)
Extensions, discoveries and improved recovery, less related costs	1,339	—	5,938	—	868	—
Changes in estimated future development costs	(17)	13	(422)	—	9	—
Development costs incurred during the period	503	—	263	—	160	—
Revisions of previous quantity estimates	(1,037)	39	(976)	34	(308)	28
Accretion of discount	2,208	23	347	4	263	7
Net change in income taxes	5,335	25	(6,009)	(42)	(473)	3
Purchases of reserves in place	233	—	1,735	—	680	—
Sales of reserves in place	16	—	(14)	—	(207)	—
Changes in production rates, timing and other	(1,354)	80	151	—	87	—
Net change	$ (9,731)	$ (65)	$11,360	$ 94	$ 1,264	$ (4)

(1) Includes operations in the United States, Canada, Brazil and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders of
El Paso Corporation:

In our opinion, based upon our audits and the report of other auditors, the consolidated financial statements listed in the Index under Item 14(a)(1) present fairly, in all material respects, the financial position of El Paso Corporation and its subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, based on our audits and the report of other auditors, the financial statement schedule listed in the Index under Item 14(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. The consolidated financial statements and financial statement schedule give retroactive effect to the merger of El Paso CGP Company (formerly The Coastal Corporation) on January 29, 2001 in a transaction accounted for as a pooling of interests, as described in Note 2 to the consolidated financial statements. We did not audit the financial statements and financial statement schedule of El Paso CGP Company as of December 31, 2000 and for each of the two years in the period then ended, which statements reflect total assets of $19,066 million as of December 31, 2000, and total revenues of $26,936 million and $16,596 million for each of the two years in the period ended December 31, 2000. Those statements were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for El Paso CGP Company as of December 31, 2000 and for each of the two years then ended, is based solely on the report of the other auditors. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

As described in Notes 1 and 9, the Company adopted Statement of Financial Accounting Standards, No. 133, *Accounting for Derivatives and Hedging Activities*, on January 1, 2001.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 6, 2002

SCHEDULE II

EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2001, 2000, and 1999
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2001					
Allowance for doubtful accounts	$128	$154	$ (1)	$ (7)[1]	$274
Valuation allowance on deferred tax assets	3	—	—	—	3
Legal reserves	278	64	(124)[2]	(31)	187
Environmental reserves	308	247[3]	30	(30)	555
Regulatory reserves	48	(1)	(11)	(2)	34
Planned major maintenance accrual	51	(1)[4]	—	(14)	36
2000					
Allowance for doubtful accounts	$ 65	$ 89	$ (19)	$ (7)[1]	$128
Valuation allowance on deferred tax assets	6	—	—	(3)	3
Legal reserves	83	(10)	210[5]	(5)	278
Environmental reserves	285	56	1	(34)	308
Regulatory reserves	95	(2)	—	(45)	48
Planned major maintenance accrual	34	33	—	(16)	51
1999					
Allowance for doubtful accounts	$ 63	$ 15	$ (8)	$ (5)[1]	$ 65
Valuation allowance on deferred tax assets	5	—	1	—	6
Legal reserves	96	(2)	(7)	(4)	83
Environmental reserves	296	17	4	(32)	285
Regulatory reserves	145	(50)	—	—	95
Planned major maintenance accrual	25	26	—	(17)	34

(1) Primarily accounts written off.

(2) In 2001, we finalized our purchase price adjustment for the legal reserves related to our PG&E acquisition.

(3) Of this amount, $232 million relates to additional environmental remediation liabilities recorded in connection with the events described in Note 14.

(4) We accrued $23 million in 2001 and reversed $24 million of reserves for the Corpus Christi refinery leased to Valero in June.

(5) Of this amount, $53 million was the legal reserve we acquired in connection with our purchase of PG&E's Texas Midstream operations. We recorded an additional $159 million for legal reserves related to purchase price adjustments on our PG&E acquisition.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information under the captions "Proposal No. 1 — Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Part I, Item 1, Business, of this Form 10-K under the caption "Executive Officers of the Registrant."

As a result of recent clarifications in the insider trading rules, and in particular, the promulgation of Rule 10b5-1, we have revised our insider trading policy to allow certain officers and directors to establish pre-established trading plans. Rule 10b5-1 allows certain officers and directors to establish written programs that permit an independent person who is not aware of inside information at the time of the trade to execute pre-established trades of our securities for the officer or director according to fixed parameters. As of March 1, 2002, no officer or director has established a trading plan. However, we intend to disclose the name of any officer or director who establishes a trading plan in compliance with Rule 10b5-1 in future filings with the Securities and Exchange Commission.

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the caption "Executive Compensation" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF MANAGEMENT

Information appearing under the caption "Security Ownership of Management" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

We own a one percent general partner interest in El Paso Energy Partners, a publicly traded master limited partnership and 26 percent of the partnership's common units. In addition, we own preferred units with $143 million liquidation value. Some of our directors, officers and other personnel who provide services for us also provide services for El Paso Energy Partners. These shared personnel own and are awarded units, or options to purchase units, in El Paso Energy Partners from time to time, and their personal financial interests may not always be completely aligned with ours.

A discussion of certain agreements, arrangements and transactions between us and El Paso Energy Partners is summarized in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, under the heading "Field Services". Also see Part II, Item 8, Financial Statements and Supplementary Data, Note 20.

Information appearing under the caption "Certain Relationships and Related Transactions" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as a part of this report:

1. Financial statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

2. Financial statement schedules and supplementary information required to be submitted.

Schedules other than that listed above are omitted because they are not applicable.

(b) Reports on Form 8-K:

- We filed a current report on Form 8-K, dated December 14, 2001 announcing El Paso's balance sheet enhancement plan.

- We filed a current report on Form 8-K, dated December 26, 2001 filing exhibits in connection with the filing by El Paso of a Shelf Registration Statement and the offering of 20,294,118 shares of El Paso's common stock pursuant to a Registration Statement on Form S-3.

- We filed a current report on Form 8-K, dated January 4, 2002 reporting Computation of the Ratio of Earnings to Fixed Charges for the five years ended December 31, 2000 and for the nine months ended September 30, 2000 and 2001.

- We filed an amended current report on Form 8-K/A, dated January 8, 2002 correcting a typographical error appearing in the January 4, 2002 report on Form 8-K.

- We filed a current report on Form 8-K dated January 11, 2002 filing exhibits in connection with the offering of medium-term notes pursuant to a Registration Statement on Form S-3.

EL PASO CORPORATION

EXHIBIT LIST
December 31, 2001

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

Exhibit Number	Description
2.B	— Agreement and Plan of Merger, dated January 17, 2000, by and among El Paso, El Paso Merger Company and The Coastal Corporation (Exhibit A to Joint Proxy Prospectus filed by El Paso on March 22, 2000).
3.A	— Restated Certificate of Incorporation of El Paso, as filed with the Delaware Secretary of State on February 1, 2001 (Exhibit 3.A to our Form 8-K filed February 15, 2001).
3.B	— Restated By-Laws of El Paso (Exhibit 3.B to our Form 8-K dated February 14, 2001).
4.A	— Amended and Restated Shareholder Rights Agreement, between El Paso and BankBoston, N.A. dated January 20, 1999 (Exhibit 1 to our Registration Statement on Form 8-A/A Amendment No. 1 filed January 29, 1999).
4.B	— Certificate of Designation, Preferences and Rights of Series C Mandatorily Convertible Single Reset Preferred Stock of El Paso Corporation as filed with the Delaware Secretary of State on October 31, 2001 (Exhibit 4.A to our 2001 Third Quarter 10-Q).
4.C	— Form of Purchase Contract between The Coastal Corporation and The Bank of New York as Purchase Contract Agent and First Supplement to the Purchase Agreement dated as of January 29, 2001 among The Coastal Corporation, El Paso and The Bank of New York, as Purchase Contract Agent (Exhibit 4.D to our 2000 Form 10-K).
4.D	— Indenture dated as of May 10, 1999, by and between El Paso and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to our Form 8-K dated May 10, 1999).
10.A	— $3,000,000,000 364-Day Revolving Credit and Competitive Advance Facility Agreement, dated June 11, 2001, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties to the Agreement, The Chase Manhattan Bank, ABN Amro Bank, N.V., and Citibank N.A., and as co-documentation agents for the Lenders, and Bank of America, N.A. and Credit Suisse First Boston, as co-syndication agents for the Lenders (Exhibit 10.A to our 2001 Second Quarter 10-Q).
10.B	— $1,000,000,000 3-Year Revolving Credit and Competitive Advance Facility Agreement dated as of August 4, 2000, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties to the Agreement, The Chase Manhattan Bank, Citibank N.A. and ABN Amro Bank, N.V. as co-documentation agents for the Lenders and Bank of America, N.A. as syndication agent for the Lenders (Exhibit 10.B to our 2000 Third Quarter 10-Q).

+10.C	— Omnibus Compensation Plan dated January 1, 1992; Amendment No. 1 effective as of April 1, 1998, to the Omnibus Compensation Plan; Amendment No. 2 effective as of August 1, 1998, to the Omnibus Compensation Plan; Amendment No. 3 effective as of December 3, 1998, to the Omnibus Compensation Plan; and Amendment No. 4 effective as of January 20, 1999, to the Omnibus Compensation Plan. (Exhibit 10.C to our 1998 10-K); Amendment No. 5 effective as of August 1, 2001, to the Omnibus Compensation Plan (Exhibit 10.C.1 to our 2001 Third Quarter 10-Q).
+10.D	— 1995 Incentive Compensation Plan, Amended and restated effective as of December 3, 1998 (Exhibit 10.D to our 1998 10-K).
+10.E	— 1995 Compensation Plan for Non-Employee Directors, Amended and Restated effective as of August 1, 1998 (Exhibit 10.H to our 1998 Third Quarter 10-Q); Amendment No. 1, effective March 9, 1999, to the 1995 Compensation Plan for Non-Employee Directors, Amended and Restated as of August 1, 1998 (Exhibit 10.E.1 to our 1999 Second Quarter 10-Q) and Amendment No. 2, effective as of July 16, 1999, to the 1995 Compensation Plan for Non-Employee Directors, Amended and Restated effective as of August 1, 1998 (Exhibit 10.E.2 to our 1999 Second Quarter 10-Q); Amendment No. 3 to the 1995 Compensation Plan for Non-Employee Directors effective as of February 7, 2001 (Exhibit 10.E.1 to our 2001 First Quarter 10-Q).
*+10.E.1	— Amendment No. 4 to the 1995 Compensation Plan for Non-Employee Directors effective as of December 7, 2001.
+10.F	— Stock Option Plan for Non-Employee Directors, Amended and Restated effective as of January 20, 1999 (Exhibit 10.F to our 1998 10-K) and Amendment No. 1, effective as of July 16, 1999, to the Stock Option Plan for Non-Employee Directors, Amended and Restated effective as of January 20, 1999 (Exhibit 10.F.1 to our 1999 Second Quarter 10-Q); Amendment No. 2, effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 2001 First Quarter 10-Q).
+10.G	— 2001 Stock Option Plan for Non-Employee Directors, effective as of January 29, 2001. (Exhibit 10.1 to our Form S-8 filed June 29, 2001).
*+10.G.1	— Amendment No. 1, effective as of February 7, 2001, to the 2001 Stock Option Plan for Non-Employee Directors.
+10.H	— 1995 Omnibus Compensation Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.J to our 1998 Third Quarter 10-Q); Amendment No. 1 effective as of December 3, 1998, to the 1995 Omnibus Compensation Plan; Amendment No. 2 effective as of January 20, 1999, to the 1995 Omnibus Compensation Plan (Exhibit 10.G.1 to our 1998 10-K).
+10.I	— 1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8 filed May 20, 1999); Amendment No. 1 effective as of February 7, 2001, to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our First Quarter 10-Q).
+10.J	— 2001 Omnibus Incentive Compensation Plan, effective as of January 29, 2001. (Exhibit 10.1 to our Form S-8 filed June 29, 2001).
*+10.J.1	— Amendment No. 1, effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan.
*+10.K	— Supplemental Benefits Plan, Amended and Restated effective December 7, 2001.

+10.L	— Senior Executive Survivor Benefit Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our 1998 Third Quarter 10-Q); Amendment No. 1 effective as of February 7, 2001, to the Senior Executive Survivor Benefit Plan (Exhibit 10.I.1 to our 2001 First Quarter 10-Q).
+10.M	— Deferred Compensation Plan, Amended and Restated effective as of December 3, 1998. (Exhibit 10.J to our 1998 10-K); and Amendment No. 1 effective as of January 1, 2000, to the Deferred Compensation Plan (Exhibit 10.K.1 to our 2000 Second Quarter 10-Q); Amendment No. 2 effective as of February 7, 2001, to the Deferred Compensation Plan (Exhibit 10.J.1 to our 2001 First Quarter 10-Q).
*+10.M.1	— Amendment No. 3, effective as of April 1, 2001 to the Deferred Compensation Plan.
*+10.M.2	— Amendment No. 4 to the Deferred Compensation Plan effective as of December 7, 2001.
+10.N	— Key Executive Severance Protection Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.O to our 1998 Third Quarter 10-Q); Amendment No. 1 effective as of February 7, 2001, to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter 10-Q).
+10.O	— Director Charitable Award Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to the our 1998 Third Quarter 10-Q); Amendment No. 1 to the Director Charitable Award Plan effective as of February 7, 2001 (Exhibit 10.L.1 to our 2001 First Quarter 10-Q).
+10.P	— Strategic Stock Plan, Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed January 14, 2000); Amendment No. 1 effective as of February 7, 2001, to the Strategic Stock Plan (Exhibit 10.M.1 to our 2001 First Quarter 10-Q).
+10.Q	— Domestic Relocation Policy, Effective November 1, 1996 (Exhibit 10.Q to EPNG's 1997 Form 10-K).
+10.R	— Employee Stock Purchase Plan effective as of January 20, 1999 (Exhibit 10.1 to our Form S-8, filed May 20, 1999) Amendment No. 1 to the Employee Stock Purchase Plan effective as of May 24, 1999 (Exhibit 10.T.1 to our 1999 Second Quarter Form 10-Q): Amendment No. 2 to the El Paso Employee Stock Purchase Plan effective as of October 1, 1999; Amendment No. 3 to the Employee Stock Purchase Plan effective as of March 14, 2000 and Amendment No. 4 to the Employee Stock Purchase Plan effective as of January 1, 2001 (Exhibit 10.T.1 to our 2000 10-K); Amendment No. 5 to the Employee Stock Purchase Plan effective as of February 7, 2001 (Exhibit 10.T.2 to our 2001 First Quarter 10-Q); Amendment No. 6, effective as of August 1, 2001 to the Employee Stock Purchase Plan (Exhibit 10.T.2 to our Third Quarter 10-Q).
+10.S	— Executive Award Plan of Sonat Inc., Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.R to our 1999 Third Quarter 10-Q); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter 10-Q).
+10.T	— Omnibus Plan for Management Employees, Amended and Restated effective as of December 3, 1999; Amendment No. 1 effective as of December 1, 2000, to the Omnibus Plan for Management Employees; Amendment No. 2 effective as of February 7, 2001, to the Omnibus Plan for Management Employees; and Amendment No. 3 to the Omnibus Plan for Management Employees effective as of December 7, 2001 (Exhibit 10.1 to our Form S-8 filed February 11, 2002).

+10.U	— Employment Agreement, Amended and Restated effective as of February 1, 2001, between El Paso and William A. Wise (Exhibit 10.O to our 2000 Form 10-K).
+10.V	— Promissory Note dated May 30, 1997, made by William A. Wise to El Paso (Exhibit 10.R to EPNG's Form 10-Q, filed May 15, 1998); Amendment to Promissory note dated November 20, 1997 (Exhibit 10.R to EPNG's 1998 First Quarter 10-Q).
10.W	— Pledge and Security Agreement, and Promissory Note, each dated August 16, 2001, by and between El Paso and William A. Wise. (Exhibit 10.CC to our 2001 Third Quarter Form 10-Q).
+10.X	— Letter Agreement dated February 22, 1991 between EPNG and Britton White Jr. (Exhibit 10.V to our 1999 Third Quarter Form 10-Q).
*+10.X.1	— Professional Services Agreement dated December 31, 2001, between El Paso and Britton White Jr.
+10.Y	— Employment Agreement dated June 16, 1999, between El Paso and Ralph Eads (Exhibit 10.W to our 2000 10-K).
10.Z	— Form of Stock Pledge Agreement, dated February 21, 2001, by and between El Paso and the named executives therein; and Form of Promissory Note dated February 1, 2001, in favor of El Paso by named executives therein; and listing of certain executive participants. (Exhibit 10.Y to our 2000 10-K).
*+10.AA	— Form of Agreement to Restate Balance of certain compensation under the Estate Enhancement Program dated December 31, 2001, by and between El Paso and the named executives on the exhibit thereto, and Form of Promissory note dated December 31, 2001, in favor of El Paso by trusts established by named executives, loan amounts, and interest rates.
*21	— Subsidiaries of El Paso.
*23.A	— Consent of Independent Accountants, PricewaterhouseCoopers LLP
*23.B	— Consent of Independent Auditors, Deloitte & Touche LLP
*23.C	— Consent of Huddleston & Co., Inc.
*99.1	— Opinion of Independent Accountants, PricewaterhouseCoopers LLP
*99.2	— Opinion of Independent Auditors, Deloitte & Touche LLP

Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and our consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 15th day of March 2002.

EL PASO CORPORATION
Registrant

By /s/ WILLIAM A. WISE

William A. Wise
Chairman of the Board,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of El Paso Corporation and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ WILLIAM A. WISE (William A. Wise)	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	March 15, 2002
/s/ H. BRENT AUSTIN (H. Brent Austin)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 15, 2002
/s/ JEFFREY I. BEASON (Jeffrey I. Beason)	Senior Vice President and Controller (Principal Accounting Officer)	March 15, 2002
/s/ BYRON ALLUMBAUGH (Byron Allumbaugh)	Director	March 15, 2002
/s/ JOHN M. BISSELL (John M. Bissell)	Director	March 15, 2002
/s/ JUAN CARLOS BRANIFF (Juan Carlos Braniff)	Director	March 15, 2002
/s/ JAMES F. GIBBONS (James F. Gibbons)	Director	March 15, 2002
/s/ ANTHONY W. HALL JR. (Anthony W. Hall Jr.)	Director	March 15, 2002
/s/ RONALD L. KUEHN, JR. (Ronald L. Kuehn, Jr.)	Director	March 15, 2002

Signature	Title	Date
/s/ J. CARLETON MACNEIL JR. (J. Carleton MacNeil Jr.)	Director	March 15, 2002
/s/ THOMAS R. MCDADE (Thomas R. McDade)	Director	March 15, 2002
/s/ MALCOLM WALLOP (Malcolm Wallop)	Director	March 15, 2002
/s/ JOE B. WYATT (Joe B. Wyatt)	Director	March 15, 2002